UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF LOUISIANA

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IN RE: OIL SPILL BY THE OIL RIG *DEEPWATER HORIZON* IN THE GULF OF MEXICO ON APRIL 20, 2010

DOCKET NO. MDL-2179
SECTION "J"
NEW ORLEANS, LA
TUESDAY, OCTOBER 15, 2013

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IN RE: THE COMPLAINT AND PETITION OF TRITON ASSET LEASING GMBH, ET AL

DOCKET NO. 10-CV-2771
SECTION "J"

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UNITED STATES OF AMERICA
V.
BP EXPLORATION & PRODUCTION, INC., ET AL

DOCKET NO. 10-CV-4536
SECTION "J"

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DAY 9 AFTERNOON SESSION
TRANSCRIPT OF NONJURY TRIAL PROCEEDINGS
HEARD BEFORE THE HONORABLE CARL J. BARBIER
UNITED STATES DISTRICT JUDGE

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I N D E X

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P-R-O-C-E-E-D-I-N-G-S

TUESDAY, OCTOBER 15, 2013

A F T E R N O O N   S E S S I O N

(COURT CALLED TO ORDER)

THE DEPUTY CLERK: All rise.

THE COURT: All right. Please be seated, everyone.

All right. Mr. Fields, you may resume your direct.

MR. FIELDS: Thank you, Your Honor.

One housekeeping matter, if you don't mind.

THE COURT: Sure.

MR. FIELDS: The Court, obviously, reviewed the video deposition excerpts from Jaime Loos. At this point, we would like to offer those into evidence.

THE COURT: Any objections?

MS. HIMMELHOCH: No, Your Honor.

THE COURT: Without objection, those are admitted.

ROBERT W. ZIMMERMAN, Ph.D.,

was called as a witness and, after being previously duly sworn by the Clerk, was examined and testified on his oath as follows:

DIRECT EXAMINATION BY MR. FIELDS:

Q. Professor Zimmerman, before we broke for lunch, we were

getting ready to talk about the third test you considered in reaching your opinions about the rock compressibility of Macondo. That test was called the acoustic velocity test?
A. Yes, I think it's also sometimes called the ultrasonic velocity test.
Q. Who conducted this ultrasonic velocity or acoustic velocity test?
A. This test was also conducted by Weatherford Laboratories.
Q. On how many samples was the acoustic velocity or ultrasonic velocity test performed?
A. These tests were performed on three samples. They were different samples than the ones used in the two previously discussed tests.
As I mentioned briefly earlier, the tests were only fully conducted on two of those three samples.
Q. Would you please display D-3702. This is a demonstrative to hopefully help us understand what the acoustic or ultrasonic velocity test is.
Can you sort of explain to the Court how the test works in general.
A. Well, essentially, these are tests to measure how fast sound waves travel through the rock. In this schematic here, it shows a typical rock core, and there are two metallic transducers on the top and the bottom. Inside those transducers are little crystals that have a special property

01:22:22 such that when an electrical current passes through the crystal, it's induces a vibration.

01:22:27 So one sends an electrical current into the upper transducer. It creates a vibration in that crystal, which then that vibration, essentially a sound wave, gets transmitted to the rock, travels to the rock through the bottom transducer, which acts as a receiver.

01:22:43 In that way, one can measure the time that it takes for the sound wave to travel through the rock, one can easily measure the length of that rock, and, from those two pieces of information, calculate the speed that the wave travels through the rock.

01:22:58 I should point out that whereas in a liquid or a gas such as air, there is only one type of wave that travels. In a solid material such as a rock, there are two different types of waves called P waves and S waves.

01:23:15 So in this test, both of those types of waves can be -- the velocity of those two types of waves can be measured.

01:23:22 Q. Why don't we pull up TREX-9056.9.1.

01:23:30 Is this an excerpt of the report containing the Weatherford acoustic velocity test results that you relied upon in forming your opinions in this case?

01:23:41 A. Yes, it is.

01:23:42 Q. Sort of help us understand what some of this data is.

01:23:44 A. Well, in the farthest-most left column is just an indication of the sample number. The next column shows the depth at which that core was taken.

Now, the most pertinent information for our purposes are in the middle panel here, ultrasonic wave velocities. This compressional wave is what I referred to earlier as a P wave. It's also known as the P wave. This shear wave is what I also are referred to earlier as the S wave.

So in this column here shows the velocity, so-called P wave velocity in units of feet per second. This column here shows the S wave velocity in units of feet per second.

As you see, the P wave velocities for all three of these cores were measured. The S wave velocities were only measured on two of those cores, and so I only used those two cores to conduct my further analysis.

Q. So to conduct your analysis, did you need data for both compressional wave velocity as well as shear wave velocity?

A. That's right. In order to convert this data into a bulk compressibility, one needs to know both the compressional velocity and the shear velocity.

Q. Can you explain for us or will you explain for us how you went about converting these ultrasonic wave velocities into the UPVC value?

A. Well, the first step of this procedure is to note that there is a very well-known relationship that expresses these velocities in terms of the elastic stiffnesses and the density of the material.

In particular, there is something called the bulk modulus. The bulk modulus is just the mathematical inverse of the bulk compressibility, so it's one divided by the bulk compressibility.

The compressional wave speed and the shear wave speed are given exactly by known equations in terms of these elastic moduli and densities.

So without going into details, the details of which are given in my report, if one has numerical values for the compressional wave speed and the shear wave speed, and if you know the density of the rock -- and you see that the density of the rock is, in fact, reported in the fourth column -- one can easily calculate all the relevant elastic moduli.

The one that's of most pertinence to us here is something called bulk modulus, which is exactly equal to one divided by the bulk compressibility.

So that part of the calculation, which is, in fact, already done here by Weatherford, although I repeated the calculation to verify, it's a simple calculation, so one now has the bulk compressibilities. One can then use some of the equations -- that I think I alluded to earlier, but, in any rate, are given in my report in detail -- and these relationships to convert the bulk compressibility into a pore compressibility.

So I used those relations to convert to a pore compressibility. Specifically, it's, again, a two-stage process. You first convert the bulk compressibility to a hydrostatic pore compressibility. Then one can convert to a uniaxial pore compressibility.

Q. How did you convert from the hydrostatic pore volume compressibility to the uniaxial pore volume compressibility, which is most relevant to this case?

A. Well, that, again, it's done from a known equation. To do that conversion, one needs to know various parameters such as the mineral compressibility, which is easily calculated. One also needs to know something called the Poisson ratio, which is another elastic parameter.

As we see here, the Poisson ratio is, in fact, measured in these tests. So one can use these values of a Poisson ratio to carry out that conversion.

Q. Would you please display D-24653.

Professor Zimmerman, what was the estimate of UPVC that you arrived at using this acoustic velocity data from the Weatherford tests?

A. Well, as one sees here, the value that I arrived at was four microsips. Maybe we should step back a bit. I should point out that there's one more step in this calculation, and that is the step that's required to convert these compressibilities that are measured during dynamic processes, such as wave provocation, to compressibilities that are relevant to relatively slowly evolving processes, such as depletion of oil from a reservoir.

It is well known that rocks are generally -- have a lower sort of dynamic compressibility than a static compressibility, so the last step in the analysis process is to look -- in particular, I used a known correlation that was developed by a Professor Amos Nur at Stanford University that allows one to convert the dynamically derived compressibility to the static compressibility. I should point out that, in fact, the dynamic compressibility is lower.

So there's another -- one calls it correction factor, or another factor that I put into my analysis, which actually increases the compressibility that one obtains from this dynamic test to give you a value that would pertain to a slowly evolving process such as oil being depleted from a reservoir.

The final result of all of those calculations is a value of about four microsips.

Q. How, in your view, does the results that you obtained from using the acoustic velocity test compare to the results that you obtained from the uniaxial compression test?

A. Well, the numerical value is actually a bit lower.

As I think I mentioned earlier, since the uniaxial compression test is the test that most directly measures the parameter that we're interested in, I consider that to be the most accurate of these tests. So I used that as the basis for my estimate of 6.35 microsips.

I used this data in the same way that I used the data from the hydrostatic stair-step test, to essentially see if it was grossly out of line with the value from the uniaxial test. If it were much, much larger, for example, then that would have given me pause to think that perhaps there might be something wrong with the uniaxial test; but, in fact, it doesn't give a grossly different value. In particular, it actually gives a lower value.

So, certainly, another point that could be made based on this data, it certainly provides no evidence at all that the actual compressibility was appreciably higher than 6.35 microsips.

Q. Let's turn to a slightly different topic. During opening statement Mr. Brock mentioned a concept called isotropy or anisotropy as it relates to rock properties, so I wanted to discuss this particular concept briefly.

Do you have the sandstone demonstrative up there? I think that's D-23958. We looked earlier at the rotary sidewall core tool, and we saw how the tool extracts the core out of the sidewall.

Can you explain the relevance of that, if any, to the concept or phenomenon called anisotropy?

Or maybe we should step back. What is anisotropy first?

A. Well, if it's okay with you'll, I'll step back even one step further. An isotropy is the general term for a situation in which the properties of a material are the same regardless of what direction they are measured in.

So for example, again, going back to steel as a very simple material which is isotropic, if one measured the compressibility of steel in this direction or in a different direction, one would get the same value, and that type of material would be called isotropic.

Anisotropy is the general term used for situations in which the physical properties that you measure might have different values depending on which direction they are measured in.

So this is an issue that needs to be thought about. The reason that it's particularly relevant in the case, if I can continue, is, as I mentioned earlier, in the reservoir, the compression occurs in the vertical direction. However, the rotary sidewall core is extracted horizontally off to the side of the borehole. So in the reservoir, the sidewall core is actually oriented in a horizontal direction.

When one takes that back into the laboratory and measures the compressibility, you're essentially measuring the compressibility of the reservoir rock in the horizontal direction.

01:32:57 Of course, the compressibility that we are, in fact, interested in is the compressibility of the rock in the vertical direction. So this raises the question as to whether or not these two values are the same or slightly different or grossly different.

Q. You're aware that some experts have suggested that there could be different UPVC values in the vertical direction versus the horizontal direction?

A. Well, I'm aware that some people have asserted that, in principle, it's a case that that could be the case, yes.

Q. As part of your analysis in this case, did you evaluate whether or not anisotropy existed in the core samples that were taken from the Macondo Reservoir?

A. Well, I did think about that, and there is some data and some analysis that one can do to partially -- to address this question.

Q. Before getting to your analysis, does the fact that a rock is anisotropic with respect to one property mean that it will be anisotropic with respect to another rock property?

A. Well, if I can back up a second. First, I would like to point out that when one talks about anisotropy, it's important to know that it's certainly a matter of degree. In other words, if one could measure any rock property to five decimal places, you might not find any piece of rock that's ideally isotropic. So there is a question of how much anisotropy exists.

Different properties can be anisotropic, so one could have anisotropy with regards to compressibility. One could have anisotropy with regards to permeability, electrical resistivity, etcetera.

In general, there is no clear, direct correlation between these; so, whereas, again, anisotropy in one property might cause you to think that there might be anisotropy in another and cause you to be sort of on the lookout for it, so to speak, but there certainly isn't any direct correlations that I'm aware of that says that if the rock is very anisotropic with respect to permeability, it also anisotropic by an equivalent percentage with regard to compressibility, so it's not that simple.

Q. Let's look at D-23701, which is a demonstrative that we looked at before lunch when we were talking about your analysis of the hydrostatic stair-step test.

What do these results tell us about whether pore volume compressibility is higher in the vertical direction versus the horizontal direction?

A. Well, this hydrostatic test that I mentioned earlier is conducted under the conditions where the stresses in all directions are equal. That's what we mean by hydrostatic.

So in a sense the compressibility that one is measuring during this hydrostatic test is an average compressibility of all three directions, the issue of compressing the rock equally in all three directions.

If it were the case, for example, that the rock were twice as compressible in the vertical direction as in the horizontal direction --

Q. So 12 versus 6?

A. -- so in that case, if, for example -- remembering that there are two horizontal directions, sort of east/west and north/south, so if it were the case that compressibility were six in the east/west direction, six in the north/south direction, but 12 in the vertical direction, the average of those three values would be the average of six plus six plus 12 divided by three, which is eight.

So if it were the case that vertical compressibility were equal to 12, I would expect the compressibility that one extracts from the hydrostatic test to have been about eight, i.e., higher than from the uniaxial test which measured the horizontal compressibility.

As we see here, the value extracted from the hydrostatic test was roughly about five. Actually, a little bit less. I, again, sort of interpret that as probably lying just within the natural variation that one core has a slightly different compressibility than the other, but certainly this evidence from this test argues strongly against the idea that vertical compressibility was equal to 12, because, again, just to recapitulate and summarize my point, if the vertical compressibility were a 12, one would expect those yellow numbers on the right, in the third and fourth column, to be about eight, and they aren't.

Q. Based on the information that you reviewed, do you believe there is any reason to increase the estimate of UPVC because of anisotropy?

A. Well, no. This is the main piece of evidence that I can rely on, as I'm trying to rely on measured data as much as possible or exclusively in drawing my opinions. Certainly, this piece of data does not argue at all for a vertical compressibility that is even slightly larger than six, or certainly it argues strongly against a vertical compressibility equal to 12.

Q. Let's turn to a different topic. As part of your work in this case, did you become aware of documents showing that for a period of time in July 2010, BP employees were discussing and using a UPVC value of 12 in some of their modeling?

A. Yes, I have read those -- that e-mail trail.

Q. Did you review those documents while you were forming your opinions in this case?

A. Yes, I had read those documents during the period when I was preparing my report, yes.

Q. Did those documents affect your opinion as to what is a reliable estimate of the reservoir's UPVC?

A. No, it did not. If I can elaborate on that, there is really nothing in those documents that indicated any scientific arguments or data to justify a value of 12 microsips.

In fact, I think a close reading of those documents shows that repeatedly -- I believe this point was mainly made by Steve Willson, and sometimes by others -- that the data clearly and very -- clearly leads to a value of about six.

So there was nothing in that discussion in terms of data or scientific arguments that would change my opinion. I guess I would characterize those discussions as sort of speculative and speculating that there might be a large anisotropic effect, but there's been certainly no data put forward or reason to believe that that was the case.

Q. In your opinion, does the data support 12 microsips as the compressibility of the Macondo Reservoir?

A. No, none of the data that I've seen. As I said, my conclusion from the data is a value somewhat larger than six. All of the other supporting data that I can look at that is relevant to this issue, none of it points in the direction of a value anywhere near 12 microsips.

Q. My final question is, is there any scientific basis in your view to conclude that the UPVC of the Macondo Reservoir was or is 12 microsips?

A. No, there is no data that I've seen that would lead me to that conclusion or that I think would support that conclusion, so no.

MR. FIELDS: Thank you.

Thank you, Your Honor.

THE COURT: All right. Thank you.

Cross.

MR. GLADSTEIN: Good afternoon, Your Honor. My name is Richard Gladstein for the United States.

CROSS-EXAMINATION BY MR. GLADSTEIN:

Q. Good afternoon, Dr. Zimmerman. Good to see you.

A. Good afternoon.

Q. Dr. Zimmerman, I'm first going to ask you some questions about your background.

You're not a petroleum engineer, correct?

A. Well, I'm a member of the Society of Petroleum Engineers, but I'm a rock mechanics person by self-definition, yes.

Q. You're not a petroleum engineer, correct?

A. I don't work as a petroleum engineer, that's correct.

Q. You're not a petroleum engineer, are you? You don't work as one, and you're not one, are you?

A. No, I'm a rock mechanics expert, yes.

Q. You're not a petroleum engineer, are you? Please just answer my question.

A. Well, I was also the governors' lecturer of rock mechanics and petroleum engineering at Imperial College for several years, but I do not work as a petroleum engineer, and I have

not put myself forward as an expert in reservoir engineering.
Q. You are not a petroleum engineer, are you?
MR. FIELDS: Objection, asked and answered, Your Honor.
MR. GLADSTEIN: Let's go to his deposition, please.
THE COURT: I really think he's answered that.
MR. GLADSTEIN: Thank you, Your Honor.
EXAMINATION BY MR. GLADSTEIN:
Q. You are not an engineer of any kind, are you?
A. Well, I have three degrees in mechanical engineering, so I'm not sure exactly what you're getting at, sir.
Q. You're not licensed as an engineer, are you?
A. No, I'm not licensed as an engineer, no.
Q. You have never been employed by an oil company, correct?
A. That's correct.
Q. You have never been involved in planning deepwater wells in the oil and gas industry, correct?
A. That's correct.
Q. You've never been involved in drilling wells in deepwater, correct?
A. That's correct.
Q. You've never been involved in drilling wells anywhere in the oil and gas industry, correct?
A. No, I'm not a drilling engineer, that's correct.
Q. You have no experience working in the Gulf of Mexico deepwater other than in this case, correct?

A. I believe that's true. This is the first time I've looked in detail at rock compressibility data from the Gulf of Mexico, yes.
Q. Thank you.
You're not a geologist, correct?
A. That is correct.
Q. You are not familiar with the geology of the Mississippi Canyon area of the Gulf of Mexico, correct?
A. Well, I would like to point out that I don't believe that such familiarity would have been necessary for me to analyze the data from Weatherford; but, having said that, no, I'm not a geologist.
Q. You're not familiar with the geology of the Mississippi Canyon area of the Gulf of Mexico, right?
A. I would agree with that, yes.
Q. Thank you.
You have never personally performed stress, deformation or other rock mechanics measurements on tests or cores from the Gulf of Mexico other than in this case?
Let me withdraw that question. That was wrong.
You've never performed any rock mechanics tests on cores from the Gulf of Mexico, correct?
A. I believe that's true, yes.
Q. You have no experience with uniaxial pore volume compressibility -- and for purposes of ease, we'll just call

that UPVC -- testing of samples from the Gulf of Mexico deepwater other than in the case, right?
A. I would like to say that the methods that one would use in doing these experiments and the methods that I would use in analyzing this data would be the same regardless of where the rocks came from.
I've certainly looked at data in the course of my career from various different places, and the methods that I've used and theoretical understanding that I've brought to bear in order to do that analysis has been essentially the same.
Q. Let's look at the answer that you gave at your deposition.
Could we please bring up the deposition 20 -- Page 20, lines 14 through 18. I'll read the question I asked you and the answer that you gave -- excuse me, that would be 21, lines 1 to 6.
"Do you have any experience with pore pressure depletion UPVC measurement of samples from the Gulf of Mexico deepwater other than in this case," is my question. And your answer was, "Specifically with regard to Gulf of Mexico rocks, no."
That answer was correct at the time you gave it, correct?
A. Yes, I believe it's still correct. I thought that's what I just answered to your question. I'm sorry if I wasn't clear enough.

Q. I apologize if I didn't hear it correctly.

You have never personally performed any UPVC tests other than as part of your Ph.D. work in 1984; isn't that right?

A. In terms of personally performing such work, as opposed to supervising students who performed such work, that is correct. My Ph.D. thesis involved a very large experimental component of measuring pore volume compressibility of several rocks in a range of pressures. Since then, I have not directly done these experiments myself in the laboratory.

Q. Thank you.

That testing involved onshore consolidated sandstones for your Ph.D., didn't it?

A. That's correct.

Q. Other than the work you performed in about 1984 related to your Ph.D. thesis, you supervised one of your students who performed UPVC tests several years ago; isn't that right?

A. Yes, one of my Ph.D. students has done pore volume compressibility measurements under my supervision, that's correct.

Q. That student had to go to Paris to conduct testing because you have no rock mechanics laboratory at the Imperial College; isn't that right?

A. No, no, that's not correct. I'm sorry if you drew an incorrect inference from my responses.

01:47:48 Those experiments were done at Imperial College. I did refer to a more recent student who has been doing measurements of acoustic wave velocities, and that is the student who did the experiments in Paris two years ago.

01:48:06 The other Ph.D. student, Ms. Al-Wardy, I believe it was about 2003, she finished her Ph.D. at Imperial College, and those experiments were done under my supervision at Imperial College, London.

01:48:19 Q. Let's see what you said in your deposition.

01:48:21 Please bring up Page 377, lines 6 through 9. 377, 6 through 9, please.

01:48:47 The question, "And you don't have experimental apparatus in your own laboratory for conducting acoustic tests, do you?" And your answer is, "Not at this time."

01:48:57 So that's what you were just clarifying; is that right, Dr. Zimmerman?

01:48:59 A. Yes, that answer was the acoustic measurements that are being made -- or were made in the last year or so in Paris by one of my Ph.D. students, yes.

01:49:07 Q. Do you have facilities in your laboratory at this time for conducting UPVC tests?

01:49:14 A. No, I think I made -- tried to make clear at the deposition, I'm not currently supervising laboratory work at Imperial College.

01:49:26 In the occasions when my students need to do laboratory work, they go overseas, such as the one in Paris, another one at TerraTek in Salt Lake City, etcetera.

Q. Thank you, Doctor.

You are not a petrophysicist, correct?

A. Well, again, not by job title. I have taught a course at Imperial College called Rock Physics, which is basically another name for petrophysics, but I'm not a petrophysicist by job title, that's correct -- yes.

Q. You're not a rock physicist, are you?

A. Actually, I would call myself a rock physicist. Those terms might sound very similar. If one looks at a very famous book called *Handbook of Rock Physics* written by a very renowned group of scientists from Stanford, one will find my name in that book mentioned 17 times, so I think that's some evidence that I do operate in the realm of rock physics.

Q. Well, let's turn to your deposition, page 33, lines 14 through 24, please.

I asked you the question, "Do you have expertise in petrophysics? Are you an expert in petrophysics?" Your answer was, "I've done some research that I think would fall under the category of petrophysics. I don't define myself as a petrophysicist."

Continuing your answer, "In some sense, one can think of petrophysics as being a subset of the broader field of rock mechanics. Petrophysics, by definition, meaning the physical behavior of rocks. Petro, I believe, is the Greek word for rocks."

MR. FIELDS: Your Honor, that's not impeachment.

THE COURT: Pardon?

MR. FIELDS: I'm sorry, Your Honor. That's not impeachment. That's not a proper impeachment.

THE COURT: I think I agree with that. I sustain that objection.

EXAMINATION BY MR. GLADSTEIN:

Q. Moving on, sir, you've never estimated compressibility other than in this case where there has been a well blowout; is that right?

A. That is correct.

Q. I'm now going to ask you several questions about the information you relied on in the preparation of your report.

For the preparation of your report, the only Macondo-specific data you relied on was from the rotary sidewall cores tested by Weatherford, correct?

A. Yes, as I mentioned previously, that was the only laboratory data that was available because I believe there were no other types of core data available.

Q. You did not look at any drilling data from the Macondo Well, did you?

A. That is correct.

Q. You did not look at any of the well log data from Macondo

in the preparation of your report, did you?
A. No, I relied on the laboratory measurements that were most pertinent to the property of uniaxial pore volume compressibility, that's correct.
Q. I'm now going to ask you some questions about the Weatherford cores.
First, on the subject of representativeness, the three UPVC samples analyzed by Weatherford constituted well less than one percent of the thickness of the reservoir as a whole; isn't that right?
A. Yes, that is correct.
Q. In fact, the eight samples, when you include the UPVC, the hydrostatic and the ultrasonic combined that you looked at, also constituted less than one percent of the reservoir, correct?
A. Yes. Yes. That's correct. Those were the only data that were available, yes.
Q. You calculated your UPVC values from the raw pressure and the strain data reported by Weatherford, didn't you?
A. Yes.
Q. Weatherford did not actually calculate or report any UPVC values, correct?
A. Actually, I believe they did report them. I didn't use their calculated values. I took their raw data and did my own calculation, which I not only believe is more accurate, but

actually led to a slightly higher value than Weatherford had calculated.

Q. Are you testifying that they came up with particular UPVC values for those three cores?

A. I seem to remember that they came up with tables of values as a function of pressure, but in any event, I didn't rely on their calculation.

Q. But they didn't measure each core at a particular microsip level, correct? That was your calculation that led you to the conclusion as to what the appropriate microsip level was, correct?

A. Yeah, it was my calculation that led me to that value, yes.

Q. Now, of the 44 rotary sidewall cores that you looked at for your UPVC tests, the three cores were approximately 1 inch in length and 1 inch in diameter; isn't that right?

A. Approximately that is correct.

Q. And the reservoir is approximately 90 feet thick; isn't that right?

A. Yes. As is almost always the case in petroleum reservoir evaluation, the amount of core represents a small fraction of the total reservoir.

Q. Now, are you aware that the reservoir was approximately 5,000 acres in area?

A. Yes.

Q. Now, are you aware that BP obtained wireline log data for the Macondo Well?
A. Yes.
Q. The log data provides information for the entire thickness of the reservoir at the well location, doesn't it?
A. Yes, I believe it does.
Q. But you did not consider the log data in the preparation of your report, did you?
A. No. I thought the most accurate values could be obtained from the direct measurements on the cores.
Q. You're not someone who looks at logs as part of your work, either on a routine basis or an occasional basis, are you?
A. That is correct.
Q. And you're by no means an expert in logs, are you?
A. I will agree with that, yes.
Q. I'm going to ask you now some questions about the differences between conventional or whole cores and rotary sidewall cores.

Dr. Zimmerman, is it your position that rotary sidewall cores are just as reliable as conventional cores for purposes of UPVC testing?
A. Well, as I've mentioned previously, I think the only real issue that needs to be discussed in this context is the issue of anisotropy, so there is an issue of anisotropy that arises when trying to convert values measured on rotary sidewall cores

to the value that you would have measured on a conventional core.

Other than that, if you're talking about anything intrinsic about the core itself, that would -- that would invalidate the actual measurement made on that core, I don't think there is, but as I mentioned previously, using rotary sidewall core does raise the issue of anisotropy that needs to be addressed.

Q. And you're aware that in deciding what type of cores to take of the Macondo Well, BP stated that rock compressibility measurements from whole cores were more reliable than compressibility rock measurements from sidewall cores; isn't that right?

A. I believe I've seen something to that effect in some of the BP documents, yes, I think so.

Q. Let's bring up TREX-11503.1.1.US.

This is an e-mail from Tanner Gansert dated October 22, 2009, with the attachment "Macondo Core VOI," value of information.

Let's go to TREX-11503.25.1.US.

Do you recall at your deposition that I asked you about this document? Do you recall the page that said, "Pro core bias compressibility measurements from rotary sidewall core are too uncertain to add value"? Do you recall that I showed you this at your deposition?

A. I'm not sure I recall that. I do remember reading these documents as part of the BP paper trail. I remember reading these documents, yes.

Q. And at the same time, BP said that whole core compressibility measurements are 100 percent accurate.

You agree that whole core compressibility measurements provide very accurate information, don't you?

A. Yes, of course. Of course, they can provide accurate information, if one has such data available, of course.

Q. And in making that decision, you recall that BP noted that whole cores would cost $7 million, do you remember that, when reviewing this information?

A. I do remember seeing that point made, yes. The costs being cited, yes.

Q. And you're also aware that rotary sidewall cores can be easily and inexpensively collected; isn't that right?

A. I'm not sure I would say *inexpensively*. I would imagine they are still quite costly to collect. I was not involved in any decision about which type of cores to take. I can only analyze, as an expert in core volume compressibility, the data such as it exists.

Q. Are you aware that BP considered rock compressibility results from whole core samples from the Santa Cruz Well in the Gulf of Mexico in developing compressibility estimates for the Macondo Well?

A. I do recall at various points they were looking at other nearby wells for the purposes of gaining some understanding, presumably, of what type of values they might expect to find.
Q. And do you recall that at the Santa Cruz Well data from whole core produced higher rock compressibility results than data from sidewall cores from the same well?
A. No. Actually, that -- I don't recall that. That wasn't my interpretation of that -- of those discussions.

My best interpretation -- and I think it's always difficult to interpret those sort of discussions because they were taking place among people, all of whom shared certain knowledge and certain background information, and I'm just sort of reading from the outside. But my interpretation was actually that they were comparing measurements on rotary sidewall cores from one reservoir to measurements made on whole core from another reservoir. That was my interpretation.
Q. Well, let's turn -- pull up the TREX and see what the document says. Maybe we're thinking about the same document; maybe we're not.

TREX-8772.1.4.US, please.

This is what I was referring to, Dr. Zimmerman. This is an e-mail from David Schott sent Tuesday, July 6, 2010.

It says, "Hi, Kelly. If you think the Macondo rocks are lower compressibility, you might use a similar upgrade going from sidewall to whole core as what we found going from the sidewall in SC and Isabela to whole core in SC."

SC there is referring to Santa Cruz.

A. And your question is, I'm sorry?

Q. Is that the discussion that you are thinking of, Dr. Zimmerman?

A. That's one of the discussions that I remember seeing, yes.

Q. And this indicates that there was an upgrade found in going from sidewall core in Santa Cruz to sidewall core -- to whole core in Santa Cruz, doesn't it?

A. That's certainly one way one could interpret this, yes.

Q. Let's look at another document and see if we can get any more insight on this.

Can we please bring up TREX-130863.1.US.

So this is another e-mail from David Schott, the reservoir engineer, October 26, 2009. David Schott notes that the new compressibility data from whole core at the nearby well Santa Cruz increased BP's estimate of the oil recovery by 16 million barrels of oil. Doesn't he?

A. I'm sorry. I'm losing you here, I'm sorry. I expected you to be reading the yellow underlines.

Q. I apologize. I'm getting ahead of myself here.

This is from Mr. Schott to Brad and he says in the highlighted, "I recommend you plan on running the bypass unless you encounter a clear set of conditions that would preclude running whole core."

Do you know what a *bypass* is?
A. I'm not exactly sure what he's talking about in this context, no.
Q. Okay. My understanding is that a bypass core is the same as a whole core, but it's off to the side of the well rather than in the borehole. Is that consistent with your understanding?
A. I honestly am not sure I have ever heard of that term used in this context before, so I don't know.
Q. Okay. It says, "Attached" -- in the second highlight, "Attached is the decision tree we use with our partner Noble to make the decision to run a bypass core in the Santa Cruz Well."
Further highlight. "As mentioned in our meeting, we were basing our development decisions on 27 percent RF" --
Do you know what *RF* stands for?
A. I guess recovery factor, my guess would be, in this context.
Q. -- "27 percent recovery factor from rotary sidewall core. With the new compressibility derived from whole core, this will push RF to 35 percent," continuing to the end of the sentence there, "16 mmboe increase."
That's what it says, doesn't it, Dr. Zimmerman?
A. Well, I think you just read the statement.
Q. Yeah. So in other words --
A. I'm not sure what conclusion you're trying to draw.

Q. So in other words, David Schott, the BP Reservoir Engineer, is saying based upon taking whole core at Santa Cruz, in addition to the sidewall core, they increase their expectation for obtaining more oil out of that well significantly. The difference between 27 percent recovery factor and a 35 percent recovery factor; isn't that right?

MR. FIELDS: Objection, Your Honor. Lack of foundation.

THE COURT: Overrule the objection.

EXAMINATION BY MR. GLADSTEIN:

Q. Dr. Zimmerman --

THE COURT: Wait. Did he ever respond to that question? I overruled the objection. Do you want an answer or not?

MR. GLADSTEIN: I would like him to, Your Honor.

THE WITNESS: Again, I'm sorry --

THE COURT: Do you remember the question?

THE WITNESS: No, Your Honor. I'm sorry. Even before the objection, I was having trouble following the line of questioning, I'm sorry.

THE COURT: Restate your question.

EXAMINATION BY MR. GLADSTEIN:

Q. Dr. Zimmerman, based upon this e-mail, it looks like the -- BP expected that the amount of oil that they were going to be able to get out of the Santa Cruz Well was going to increase from a recovery factor of 27 percent based on the sidewall core data to a recovery factor of 35 percent based upon the whole core data; isn't that right?

A. Well, that's what it says, yes. It's not -- again, I can try to interpret this. It's not fully clear to me whether the increase in STOIIP comes from different compressibilities or it comes from different recovery factor, because you might have recovery factor appearing in their calculation of how certain they are about the oil in place.

So based on this, quite honestly, I can't tell which one of those two factors led them to increase the STOIIP.

But certainly on the face of it, I still don't really see a clear statement here that the compressibility is measured on the so-called whole core were twice as high as those measured on the rotary sidewall core. I honestly don't actually see that stated here clearly.

Q. Dr. Zimmerman, I'm now going to move on to ask you a series of questions about the orientation of sidewall cores.

Now, it's preferable to have the orientation of the core in the lab match the orientation of compaction in the reservoir, isn't it?

A. Yeah, I think there is no doubt, I thought I mentioned that earlier, that all other things being equal, if one had a core that were oriented in the vertical direction, it would be preferable because it would remove this issue of anisotropy.

So yes, it certainly would be preferable if it were, if it were possible to be the case, yes.

Q. And the testing conditions in the laboratory did not match, I believe you've testified, the in situ conditions in the actual reservoir with respect to the orientation or direction of the cores, correct?

A. Yes. As I've said, measurements made in the laboratory were essentially measuring horizontal compressibility, not vertical compressibility, and that's what initiated the previous discussion about possible anisotropy.

Q. Are you aware that BP had concerns with respect to the Isabela Well about the orientation of sidewall cores in terms of their ability to accurately predict compressibility?

A. I think, yeah, this was one of the themes that seemed to run through the e-mail trail that I read, was this issue of whether or not -- they were unsure that measurements made on horizontal oriented sidewall cores would accurately reflect the vertical compressibility. That was a concern that they had, yes.

Q. And that was a concern that they expressed in this July 6th and July 8th period when they came up with the most -- new most likely recommendation of 12 microsips; isn't that right?

A. Yeah. It's right in the sense that it was the same period of time that both of those -- that those concerns were mentioned and this value of 12 was hypothesized.

As I mentioned before, I still have not seen any data to support that, but it is true that some people were suggesting a value of 12 for various reasons.

Q. And, in fact, in this period between July 6th and July 8th, when the new recommendation was made, BP considered UPVC data from the Isabela Well as part of the data that they considered in making this new recommendation, didn't they?

A. Well, they did seem to be looking at data from different wells, yes. That seemed to be part of their discussion, yes.

Q. Okay. Let's turn to TREX-800 -- I'm sorry, 8770.1.2.US, please.

And this is one of those e-mails. And I know, Your Honor, you're probably tired of them already, and I'm going to try not to belabor this.

So this is an e-mail from Jessica Kurtz sent July 6, 2010, to Kelly McAughan, David Schott, cc: Robert Merrill, "Subject: Compressibility." "Attachments: Isabela Comp Table, Isabela Rock Mechanics Report."

So they were considering the data from the Isabela Well at the time that they decided to make a new recommendation, isn't that right, Dr. Zimmerman?

A. Well, actually, I think this may well be the document that I was remembering that seemed to imply to me that they were comparing sidewall cores at Isabela to whole core at

Santa Cruz. So if I can return to that point, this is what was in my mind, I think, when I answered -- gave the answer to your question a few minutes ago.

Q. Okay. It says -- the next highlight says, "Also, included is the Isabela sidewall core data." And the next highlight, "We have since updated this table to the ones I sent previously based on the Santa Cruz, SC, whole core."

Now, could we please go to TREX-11505.1.1.US.

Again, this is one of the documents that we reviewed at your deposition, title, "Isabela Core Volume Compressibility Evaluation," reviewed by Stephen Willson, along with David Schott, BP personnel, October 11, 2007.

If we could turn to 11505.3.1.US, Figure 1, please.

Dr. Zimmerman, this figure concerns the different impact of testing rotary sidewall cores versus whole cores, doesn't it?

A. Yes, I believe it does.

Q. So on the left, in the field, compaction occurs perpendicular to the bedding planes. That's what you've indicated; isn't that right?

A. Yes, that's correct.

Q. And according to this drawing, you'll see the layers of rock are horizontal, but the compaction, because the pressure is applied vertically, the compressibility is going to be more, isn't that right, Dr. Zimmerman?

A. Well, maybe; maybe not. This just is another way of addressing the question of anisotropy that we discussed earlier. In some cases the rock would be more compressible in the vertical direction. There actually are cases where rocks are less compressible in the vertical direction. It's certainly more common that they are more compressible in vertical direction.

There are also many rocks where the compressibility in the two directions are essentially the same to a very high degree of accuracy.

I can also say that I'm not aware of any laboratory data that I've seen in the refereed, peer-reviewed scientific literature that shows anisotropy factor of two for a sandstone. I just have not seen such data in the peer-reviewed scientific literature.

Q. On the right corner of this figure, it says, "Lab compaction occurs parallel to bedding planes."

So in other words, this is a horizontal core, correct, taken off the side of the well, and it's turned on its head so that your layers are up and down and that that's going to be -- in the lab it's going to have a -- what they are showing here is a stiffer result, less compression; isn't that right?

A. Again, it depends on the specific rock. It also supposes that there are clearly defined bedding planes and striations in the rock, which in many cases in sandstones, when you look at them -- and I'm not an expert in petrographic analysis of sandstones, but I have looked at thin sections -- and in many cases you can't see any apparent orientation of bedding plane.

So this is one possible scenario, but this is not the general universal case.

THE COURT: Where does this document come from? What is this document I'm looking at?

MR. GLADSTEIN: So this is a report that BP did on the compressibility at a nearby well, Isabela, and they are raising, in the document, certain concerns they have about the reliability of the sidewall core values that were obtained.

THE COURT: But it's a BP document?

MR. GLADSTEIN: Yes, I'm sorry, Your Honor.

THE COURT: That's what I was trying to figure out.

MR. GLADSTEIN: I should have answered more succinctly.

MR. FIELDS: Your Honor, sorry, it seems to me this whole line of questions is really irrelevant to the issues at hand here.

THE COURT: Well, I'm not sure.

MR. GLADSTEIN: I don't think it's irrelevant. He said that anisotropy is key.

THE COURT: Go ahead.

EXAMINATION BY MR. GLADSTEIN:

Q. So BP states, "PVC tests in the laboratory may underpredict compaction since rotary sidewall core undergo compaction in parallel to bedding planes in which rocks are typically stiffer. In the field, compaction occurs perpendicular to bedding in which rocks are typically softer."

You agree with that statement, don't you?

A. Yeah, as a qualitative statement, I think that's generally true. As I mentioned, there are actually cases where rocks are stiffer in the vertical direction, but more commonly, if there is a difference in stiffness, the rock might be more -- might be more compressible in the vertical direction. That's certainly a possibility.

And I think that was, again, the starting point in the whole discussion of anisotropy, and that is, in fact, what caused me to do my analysis based on the stair-step porosity tests to try to rule out the existence of a gross amount of anisotropy.

Q. Since most sedimentary and metamorphic rocks are anisotropic, the effect of anisotropy on strength is of great importance; isn't that right?

A. Well, I believe that's a quote from my book, *Fundamentals of Rock Mechanics,* so yes, but also I point out that it was a discussion of strength, which is very different from compressibility. We can -- I can elaborate on that if you want. But certainly, no, anisotropy is an issue that needs to be addressed, and I think I tried to address it the best I

02:17:54 could based on the actual data that we had at hand.
02:18:07 Q. How do you define laminations?
02:18:13 A. I'm not sure that I would define it because I think we've already established I'm not a petrophysicist or a geologist, but in layman's terms, I think of it as some sort of obvious layering that one could determine by visual inspection of a rock.
02:18:29 Q. To determine if laminations were present in a CT scan of a core, you would look at different levels of darkness indicating different properties of thin layers of the rock; isn't that right?
02:18:41 A. That's what I would do, yes.
02:18:42 Q. Now, you've seen CT scans of the cores that were sampled for the UPVC samples; isn't that right?
02:18:52 A. Yes, I have.
02:18:52 Q. And you saw laminations in at least one of those three cores that were UPVC tested, didn't you?
02:19:00 A. I think -- I think you're referring to a discussion we had at the deposition, and I think at the time I did say that it might be possible to detect what seemed to my untrained eye as being laminations in one of those cores, yes.
02:19:14 Q. Dr. Zimmerman, let's turn to the subject of sample dimensions.
02:19:22 Rotary sidewall cores are normally 2 inches in length; isn't that right?

A. Possibly. It sounds about right. It might vary from vendor to vendor, but yes.
Q. The three rotary sidewall cores tested for UPVC were approximately 1 inch in length; isn't that right?
A. That's why I was -- my little hesitation was, yes. The cores that were used in these tests that we're referring to here that were carried out by Weatherford were, I believe, about 1.1 to 1.25 inches in length, yes.
Q. Let's turn to TREX-11501.1.1.US, please.
Do you recall that at your deposition I showed you some documents from the Weatherford website, one regarding rotary sidewall cores?
A. I think I've seen this document before. I can't remember exactly where, but I believe I've seen it.
Q. And Weatherford says on its website, in the highlighted, "This method uses a small robotic core bit of approximately 1 inch in diameter to drill sideways into the formation, period. The 2-inch long core is then removed into the main coring tool for retrieval."
Does that refresh your recollection as to the normal length for rotary sidewall cores?
A. Okay. Well, that's what it seems to say here, yes.
Q. Now, you would agree the length -- the length-to-diameter ratio is an important consideration in strength measurements; isn't that right?

A. In strength measurements, which, again, I'll mention are very different, really completely different measurements than compressibility measurements.

In certain types of strength measurements one tries to compress the rock to a point where the fault plane passes through the rock. In general, that fault plane comes in at something like a 45-degree angle. And it is generally thought that you want -- you generally want the fault -- the core to be sufficiently long such that this fault plane breaks through the rock at the side rather than breaking through at the upper plate.

So this issue of length-to-diameter ratio is an important consideration when doing that particular type of strength measurement. I don't think any of those considerations are relevant to compressibility measurements where by definition you're not compressing the rock until it breaks, so --

Q. For triaxial rock mechanics tests a length-to-diameter ratio of 2 to 1 or 3 to 1 is commonly used; isn't that right?

A. Yes, I would say that's true.

Q. Now, it's your position that the length-to-diameter ratio of rotary sidewall cores does not impact the UPVC results; is that correct?

A. Yes. I don't believe the length-to-diameter ratio has an appreciable effect on pore volume compressibility measurements, that is true.

Q. Are you aware that BP disagreed with that position in the Isabela memo that we were just looking at?

A. I'm not sure that I remember that that's what they say, but I prefer to answer in terms of what I believe and what I understand based on my knowledge of rock mechanics.

Q. Could we please turn to TREX-11505.1.2.US.

Again, this is a document that we looked at, at your deposition. The first sentence concerns the UPVC value that was determined by the laboratory for Isabela, which was 14.6 for the upper sands and 13.7 for the lower sands.

Then there is a sentence that says, "Testing protocol and sample size effects (specifically length-to-diameter ratio) may result in this value underestimating the actual reservoir compressibility."

Do you disagree with BP with respect to that statement?

A. I'm not aware of any information, either experimental or theoretical, that would lead me to make that conclusion. So I'm not sure on what they've based this conclusion, but I guess my simple answer is, no, I don't believe -- I don't think I do agree with that.

Q. Okay. Dr. Zimmerman, thank you.

I'm now going to ask you some questions about the Weatherford testing procedures.

On the subject of saturation with brine, the testing conditions in the laboratory did not match the in situ conditions in the actual reservoir with respect to saturation of the cores; isn't that right?
A. Well, they are not necessarily intended to match the in situ conditions with regard to fluid properties. The purpose of pore fluid in a pore compressibility measurement is essentially and solely to provide a pressure to the walls of the cores. As such, various different pore fluids can and have been used in the past, and various different fluids are appropriate.
Q. Dr. Zimmerman, I'm going to ask the same question because I don't think you answered my question. The testing conditions in the laboratory did not match the in situ conditions in the actual reservoir with respect to the saturation of the cores; isn't that right?
MR. FIELDS: Objection. Asked and answered, Your Honor.
THE COURT: Overruled.
THE WITNESS: Your questions did not match in terms of saturation. In terms of oil/water saturation; is that what you're getting at?
EXAMINATION BY MR. GLADSTEIN:
Q. Let me try it again, Dr. Zimmerman. The testing conditions in the laboratory did not match the in situ

conditions in the actual reservoir with respect to the saturation of the cores; isn't that correct?

A. In my experience, that's true in all laboratory pore volume compressibility measurements. I'm not aware of anyone who makes them with in situ reservoir mixture of oil and brine.

So the answer is yes, it's not intended to match the properties, and it didn't match the properties, as is universally the case in my experience. That's not the purpose of pore volume compressibility measurement.

Q. The in situ saturation of the rock in the Macondo Reservoir is with saltwater or brine; isn't that correct?

A. Well, there's brine and hydrocarbon in the Macondo Reservoir, yes.

Q. But the testing at Weatherford was done with samples that were cleaned and dried so that the in situ liquid was removed and then saturated with kerosene before the UPVC test; isn't that right?

A. As is commonly done in many UPVC tests, yes, that's exactly what they did.

Q. The same was done with respect to the ultrasonic velocity measurements, they were tested under dry conditions; isn't that correct?

A. That's correct, because that's, in fact, the intention of

that test is to measure the dry velocities, yes.
Q. Now, in your book under compressibility of sandstones, you suggested a testing procedure that included saturation with brine; isn't that correct?
A. I wouldn't say I suggested. I described the procedure that I used in my Ph.D. In those experiments, I did use brine as a saturating fluid. That's certainly also an acceptable procedure to use, yes.
Q. In your book, you said that the sample should be dried to remove any moisture from the pore and then afterwards carefully saturated with brine; is that correct?
A. That's the method that I use in my Ph.D. experiments, that's correct.
Q. You learned about that method from your professor, who had years of experience with this sort of test, as a matter of his protocol; isn't that right?
A. Yes, that's correct.
I should also say that in my book I do mention many other famous experiments on pore volume compressibility that used kerosene.
Q. There were two other mentions of articles in your book where kerosene was used; isn't that right?
A. Two of the most famous and important papers in the history of the field of pore volume compressibilities, yes.
Q. When you had a Ph.D. student a few years ago who did

compressibility measurements, that student used brine as a pore fluid; isn't that right?
A. Yes.
Q. Now, in your Expert Report, you failed to analyze the effect of testing at saturation conditions different from the in situ saturation conditions of the reservoir; isn't that right?
A. I do not believe that the pore fluid will have an effect on the pore volume compressibility as long as that fluid is not something like an acid, obviously, which would eat away the rock grains; but, any sort of sensible fluid that one would use, I don't believe would have an effect on the compressibility.
As I said, the purpose of the fluid in the pore volume compressibility test, if we're just focusing on those tests, is merely to apply a pressure. One could, in fact, do that with nitrogen. One doesn't do that for safety reasons, but you could just as well use air or nitrogen.
It's just the mechanical effect that one is trying to measure in these pore volume compressibility tests.
Q. Thank you.
Let's move to the question of temperature. The testing conditions in the Weatherford laboratory did not match the in situ conditions in the actual reservoir with respect to the temperature of the cores; isn't that correct?

A. That's correct. The laboratory tests were done at so-called room temperature, which is about 20 degrees C. I believe the reservoir was a temperature of about 110 degrees centigrade.
Q. Which is approximately 240 degrees Fahrenheit, right?
A. Yes, I think so.
Q. In general, compressibility increases as temperature increases; isn't that true?
A. Pore compressibility increases very slightly as temperature increases. This was something that I was aware of at the time of writing the report, and I considered it to be a relatively small effect, but it is an effect, yes.
Q. The compressibility of a rock will be higher at reservoir temperature than at room temperature; isn't that true?
A. It would be slightly higher, yes.
Q. In your report, you failed to analyze the effect of testing at temperature conditions different from the in situ temperature conditions of the reservoir; isn't that right?
A. I didn't make reference to it because I knew that it would be a relatively small effect. In fact, it is an effect smaller than the -- much smaller than the difference between the measurements that we have on the three cores.
So it's an effect of a few percent, well within the range of uncertainty, just from the data that we have.
MR. GLADSTEIN: Your Honor, I would move to strike the

portion of his answer that talks about the quantification of the effect. That was one of his ten new opinions.

THE COURT: Well, I think he was just responding to your question, so I'll overrule your motion.

MR. GLADSTEIN: Thank you, Your Honor.

EXAMINATION BY MR. GLADSTEIN:

Q. Let's turn to BP's usage of 12 microsips for rock compressibility during the well integrity period.

You stated in your report, and here in court today, that you did not believe that BP's decision to recommend a new most likely rock compressibility of 12 was consistent with the data; is that correct?

A. Yeah, I think roughly speaking that's correct. I didn't see any data that justified that -- that move for changing from a value of six that the data implies to a value of 12, yes.

Q. But you listed as considered materials in your report a number of the e-mails between July 6th and July 8th, and the attachments that went with those e-mails, didn't you?

A. Yes, I have read some -- many of those e-mails, yes.

Q. These e-mails and attachments include UPVC data from other BP wells in the Gulf of Mexico, including Isabela and Santa Cruz, don't they?

A. Yes.

Q. You didn't consider that data?

A. Well, I think I mentioned earlier in my direct testimony that since there is so much variation in pore volume compressibility between one reservoir and the next, I don't believe that the best way to estimate the pore volume compressibility of a given reservoir is by reference to data taken from other reservoirs.

Q. So you disregarded that data and the opinions of the BP reservoir engineers and geomechanics who had experience in the Gulf of Mexico, didn't you?

A. I'm not sure disregarded is the right word. I considered that point. Based on what I've just said, that I don't believe that one can extrapolate from one reservoir to the next, I didn't believe that measurements made on Isabela or Santa Cruz would be useful, and certainly not more useful than actual data taken from the Macondo Reservoir itself.

Q. BP had the same Weatherford core data that you rely on for your opinion, but BP determined that 12 microsips was the most likely value for rock compressibility, didn't they?

A. I'm not entirely sure that's the case. Again, my reading of those e-mails was that throughout them Steve Willson, who is their resident rock mechanics expert, was arguing for a value of six. There were a point where the value of 12 was used for certain purposes. I didn't see any scientific justification for that value of 12.

So exactly on what basis they made that decision, I'm not sure, but certainly nothing that I've read convinced me

that that was a correct scientific decision to ignore the data or modify the data and somehow jump from six to 12.
Q. You consider measured data at Macondo to be data; is that correct?
A. Yes.
Q. Wouldn't you consider measured data at Isabela to be scientific data?
A. Scientific data from a different reservoir. As I've mentioned several times, there is so much variation between compressibility of one reservoir to the next.
As you can, in fact, see from these graphs that you're alluding to, the range is much larger than the range between six and 12. So, by comparison with other reservoirs, one can get almost any answer, depending on which other reservoir you decide to use as your proxy.
Q. You would consider measured data from Santa Cruz to be data, too, wouldn't you?
A. By definition, yes.
Q. I'm now going to ask you some questions about the relative degree of --
THE COURT: Let me ask one question. What was your understanding of why the BP engineers were looking at data from these other wells at that time, from the information you've reviewed?
THE WITNESS: Well, obviously, they had a lot of

experience from these other wells. These other wells were in the Gulf of Mexico.

There did seem to be an implication on the part of some of these people that it was valid to make this type of proxy analog. I think that that's something that one would do in the lack of data, but given actual data, I don't think that in any way proxy data from a different reservoir would sort of trump or supersede data from the reservoir.

I can point -- if I can continue for a second, just going back to a very famous paper by Newman, which maybe we haven't discussed here but is mentioned in my report, his main conclusion -- this is one of the most famous papers in this field -- is that if one wants to know the compressibility of a given reservoir, you need to make measurements on the cores of that reservoir.

You cannot base it on analogs with other reservoirs or other rock measurements because there is just too much variability from one reservoir to the other.

I hope that answers your question.

THE COURT: I think so. I'm just trying to understand whether you thought there was some other reason they were doing this, other than to use it as an analog well.

THE WITNESS: No, the term "analog well" comes up a lot in their discussion, so it's clear that that's a part of their workflow to base their initial assessment of the new reservoir on ones -- and it only makes sense that -- basing it on other reservoirs that they think are similar.

I would point out though that, again, I'm not a geologist, but as I recall, the porosities of these other reservoirs were much larger than the porosity at Macondo.

So even to a layman, I'm not sure they would be such good analogs because the porosities, I believe, in these other reservoirs were over 30 percent.

But, again, this concept of analog is something that the BP reservoir engineers clearly were accustomed to using in their workflow.

MR. GLADSTEIN: Thank you, Your Honor.

EXAMINATION BY MR. GLADSTEIN:

Q. Now, your statement assumes that rotary sidewall core data is as valid for determining compressibility as whole core data; isn't that correct?

A. Well, as I said, there is this issue of anisotropy which has to be considered, so I wouldn't say that rotary sidewall core was completely as useful as whole core, if one had whole core, because, as I said, it does sort of beg the issue or raise the issue of anisotropy.

So, yes, there is that issue of anisotropy, which I think I've discussed, which is the one issue that I can see that one has to consider when judging the use -- the applicability of data on rotary sidewall cores.

Q. They had whole core at Santa Cruz, didn't they?
A. I believe that that's what we've just read, yes.
Q. So in your view -- Dr. Zimmerman, we're almost done, and I appreciate --
THE COURT: Let me interrupt you. Do we know or do you know and understand why no whole core samples were taken on the Macondo?
THE WITNESS: No, I don't know for certain why that -- there was some discussion of it in some of the BP documents. I don't know. I was not involved in that discussion.
THE COURT: Okay. All right. Go ahead.
MR. GLADSTEIN: Thank you, Your Honor.
Almost at the end, and I appreciate both of your patience on this.
EXAMINATION BY MR. GLADSTEIN:
Q. As you stated on your direct, Dr. Zimmerman, it's your view that the Macondo Reservoir rock falls into the range of weekly consolidated sandstone; isn't that true?
A. Yes. That's what I stated at my deposition, yes.
Q. If we could bring up defendants deposition D-23953, I would appreciate it. Demonstrative. Can we do that? This is D-23953. Yes, thank you.
Now, in this demonstrative that you were shown on direct, the heading is "Unconsolidated Sands Have Very Low Acoustic Velocities." You placed Macondo with a star there in

the area of the yellow triangles; isn't that correct?

MR. FIELDS: Just for the record, Your Honor, we did not use this on direct examination.

MR. GLADSTEIN: Oh, sorry, I apologize. It was one of the ones that they provided to us.

MR. FIELDS: The rule is I've got to use it first.

MR. GLADSTEIN: Oh, okay, I apologize, if that's the rule.

THE COURT: Apparently, that's the rule.

MR. BROCK: I'm sorry, as I mentioned, we have a demonstrative coach, and he works with us, like, weekly, to keep us up to speed.

EXAMINATION BY MR. GLADSTEIN:

Q. Isn't it true that based on procedures from the Weatherford labs, these cores were treated as friable or unconsolidated when they were recovered?

THE COURT: Was the word "friable"?

MS. HIMMELHOCH: Friable, yes.

EXAMINATION BY MR. GLADSTEIN:

Q. Would you define for Your Honor the term "friable," please.

A. Friable is an operational term that goes back to a paper by George Newman from Chevron in 1973. He categorized sandstones in three categories of consolidated at one extreme, unconsolidated at the other extreme -- unconsolidated, again, being a loose collection of sand grains -- but what he called friable was a situation where the rock had enough sort of coherence and a high enough level of consolidation that one could create a core and sit it on the table, but, yet, at the same time it was sufficiently weak that one could, by rubbing ones finger against it, break off some of the sand grains or break off a corner.

So friable category is somewhere between consolidated and unconsolidated. I think, for practical purposes, it's somewhat equivalent to what other people would call weakly consolidated.

Q. You are aware that Weatherford had well site procedures for handling the Macondo sidewall cores; isn't that right?

A. Yes.

Q. Now these procedures stated, "If it is determined that the cores are unconsolidated during the initial sample assessment, then the cores will be frozen in the receiver tube using a procedure"; isn't that right? Do you recall that?

A. I recall reading that, yes, I do.

Q. Do you recall that the Macondo sidewall cores were frozen after they were extracted?

A. Yes, I do recall that.

Q. Isn't it also true that Weatherford noted that numerous Macondo samples that had been recovered were fractured, broken, and in remnants?

A. Yes, I do recall that. I think that's very common with core recovery from all sorts of reservoirs, that some of the core is damaged and not usable, yes.
Q. Now, to clear up one last point related to BP's rock mechanics expert Stephen Willson, if we could bring up TREX-8774.001, please.
Thank you. If we could highlight the last sentence in the e-mail at the top -- the second to the last sentence.
So this is an e-mail from Mr. Willson, who was the BP rock mechanics expert, to David Schott, July 6, 2010, re: Macondo PVC.
In this sentence, Mr. Wilson says, "The initial response," in other words, the initial response related to, you know, we should stay with six, "was more to do with what we measured on the Macondo rotary side wall cores, which, as you correctly point out, have some inherent biases."
As you've indicated, rotary side wall cores can have inherent biases, can't they, Dr. Zimmerman?
A. Well, as I pointed out, if the rock is anisotropic, then one would measure sort of an improper value. As I mentioned earlier, based on the other data that I've looked at, I don't see any evidence that these rocks were highly anisotropic.
That raises one more point. I've look at lots of such data over the years, and I honestly don't recall ever seeing sandstones that have anisotropy factors of a factor of

two. I've never seen such laboratory data.
Q. The same Weatherford data is the same data that Mr. Willson and other BP reservoir engineers looked at and determined that the most likely pore volume compressibility for the Macondo rock was 12; isn't that correct?
A. Well, strictly speaking, I'm not sure that Steve Willson ever -- from my reading of the document, I'm not sure he ever agreed with that.
My interpretation was that he was acquiescing to that value, which was being sort of pressured on him to some extent. So him being their actual resident rock mechanics expert, I think the evidence shows that he was trying to stick to the value of about six.
Q. Let's see if this refreshes your recollection.
Could we please turn to TREX-8776.001. If you could highlight the -- one, two -- third e-mail on this page, the one from Kelly McAughan to Stephen Willson.
Do you recall looking at the e-mail that said -- from Kelly McAughan to Stephen Willson, the rock mechanics expert, "How about if we use 6, 12 and 18?" Do you recall that, Dr. Zimmerman?
A. Yes, I certainly do recall this.
Q. Thank you.
Do you recall what the rock mechanics expert responded, in the e-mail right above that?

Let's turn to that, please. Okay.

He stated, "That sounds very reasonable to me, Kelly." Do you recall that, Dr. Zimmerman?

A. This is completely consistent with my interpretation that he was essentially acquiescing to this after several days of him saying -- it was a quote which I'm sure you remember in one of his earlier e-mails saying, I don't think we could go much above six and still honor the data.

Then, after a few days of e-mails, he said, okay, sounds reasonable to me. I interpret that as saying, okay, I'm not going to argue it anymore because I've been overruled.

But anyway, getting back to my opinion, again, I would like to emphasize, I still don't see any discussion here that convinces me that the rotary sidewall core value should be multiplied by a factor of two.

MR. GLADSTEIN: Those are my questions, Dr. Zimmerman.

Thank you, Your Honor.

THE COURT: All right, sure.

Redirect.

MR. FIELDS: No redirect, Your Honor.

THE COURT: Okay. Thank you, sir. You're done.

THE WITNESS: All right. Thank you.

THE COURT: Who is the next witness for defendants?

MR. BROCK: Your Honor, our next witness is Dr. Gringarten, and I think he's in the hall. I'll step out.

THE COURT: Why don't we stop off and take about a 10- or 15-minute recess.

THE DEPUTY CLERK: All rise.

(WHEREUPON, at 2:48 p.m., the Court was in recess.)

THE DEPUTY CLERK: All rise.

THE COURT: Please be seated, everyone.

Is someone going to examine this witness?

MR. BOLES: Yes, Your Honor. I was obeying your directive to be seated.

THE COURT: I didn't mean permanently.

THE DEPUTY CLERK: Would you please raise your right hand. Do you solemnly swear that the testimony you are about to give will be the truth, the whole truth and nothing but the truth, so help you God?

THE WITNESS: I do.

ALAIN GRINGARTEN

was called as a witness and, after being first duly sworn by the Clerk, was examined and testified on his oath as follows:

THE DEPUTY CLERK: If you'll take a seat, and please state and spell your name for the record.

THE WITNESS: My name is Alain Gringarten G-R-I-N-G-A-R-T-E-N.

MR. BOLES: Dr. Gringarten, I think you better spell your first name, as well, given your country of origin.

THE WITNESS: A-L-A-I-N.

MR. BOLES: Your Honor, Martin Boles on behalf of BP and Anadarko. If I may proceed?

THE COURT: Yes.

VOIR DIRE EXAMINATION BY MR. BOLES:

Q. Dr. Gringarten, can you tell Judge Barbier what you were asked to do for BP in this case.

A. I was asked to evaluate the total discharge from the Macondo Well.

Q. Let's review a little bit about your background that prepared you for this.

Let's go to D-23614.

Where did you get your education related to your work here, Dr. Gringarten?

A. I have an MSc and PhD from Stanford University. Then I was a research fellow at the University of California at Berkeley.

Q. That's a research fellow?

A. Yes.

Q. Where do you work now?

Let's look at D-23616.

A. I'm a professor of petroleum engineering at Imperial College.

Q. Imperial College.

Have you had any leadership positions there?

A. Yes, I'm the Director of the Centre for Petroleum Studies

and I'm the chair of petroleum engineering.
Q. Did you go directly from your Stanford and Berkeley graduate and postgraduate work to academia?
A. No. I spent 25 years in industry.
Q. Let's look at an overview of that. D-23615.
Can you summarize your work in industry before you went to Imperial College?
A. I spent five years -- well, initially, I spent four years with the French Geological Survey. Then I spent five years in Schlumberger.
THE REPORTER: I'm sorry?
THE WITNESS: In Schlumberger, S-C-H --
THE REPORTER: Oh, Schlumberger.
THE WITNESS: Yeah, okay.
THE COURT: That's how we pronounce it down here.
THE WITNESS: We might have a few of these.
THE COURT: Go ahead.
THE WITNESS: Then I spent 14 years with Scientific Software - Intercomp before joining Imperial College.
EXAMINATION BY MR. BOLES:
Q. After joining Imperial College, did you continue to do consulting work for industry?
A. Yes. I've been, you know, very active in consulting for oil industry on essentially well test analysis issues.
Q. Now, we're going to be talking a lot about well test

analysis. Can you briefly summarize what that is.

A. Well, in short, well test analysis is a study of pressure and rate to obtain permeability and other information that characterize the reservoir.

Q. Was well test analysis part of the work you did to analyze the Macondo Well and come up with a cumulative flow estimate?

A. Yes.

Q. Let's go back to the earlier work you did in industry after you left your postgraduate work at Berkeley.

Under Schlumberger, in the third bullet point, it says, "Founded well test analysis service." Can you describe for Judge Barbier what that refers to.

A. I was hired by Schlumberger to create surveys with engineers that would conduct well tests for their clients.

The reason I was hired was because I had published a number of papers on well test analyses prior to that. So what I did there is set up a service that would include -- you know, defining the service, training the engineers, develop the methodology -- training the engineers, developing methodology, you know, and defining the complete service provided to the clients.

Q. Prior to that, what had Schlumberger and other service companies in the oil industry done with respect to well test analysis?

A. Prior to that, they were not doing interpolation. What the service company was doing is taking measurements and providing the measurements to the clients, and they thought that the responsibility for interpreting the data was with the clients.

Then in 1978, they decide to, you know, go further and provide interpreted data to the client, and that's where, you know, I was hired.

Q. In the second main bullet point there in your industry experience, Scientific Software - Intercomp, the last sub-bullet says, "Developed first commercial well test analysis software." Can you describe a little bit more about that for Judge Barbier.

A. Yes. Only certain operating companies had their own software for doing different things, including interpreting well tests data. I developed such a software when I was in Schlumberger for the well test analysis service.

I redeveloped it in Scientific Software, with the objective of selling it to oil companies. So the first software -- that was the first software that was sold to -- that became commercial in 1983.

Q. Does that software still exist as a commercial product?

A. Yes. It is called Interpret. That's a software which I have used for doing the work I've done for BP.

Q. Let's go to D-23617.

We've summarized, Dr. Gringarten, some of your professional contributions on this slide. We won't go over all of them, but if you could tell Judge Barbier about the third bullet, "Standardized well test analysis methodology."

A. Yes. That was part of the work that I did for creating well test analysis software -- sorry, I managed the service in Schlumberger.

What I wanted is to -- something that the engineer doing -- interpreting well test data, pressure and grade, would have confidence in their analyses, and also the clients would be confident in the analysis they received.

So I developed a number of check and balance because the problem was with techniques that existed until then, the -- those -- there were a number of methods of interpreting tests, but they were not used consistently. So you could have widely different result of the well test analyses depending on what method used.

So, therefore, the well test analyses was not really reproducible, and people were not confident in the results of these analyses.

What I did is reorganized the various interpretation technique so that it became consistent. The result was that if you give well test data to somebody, and they follow -- to several people, and they follow that -- they will get the same result, which is something that was not available before.

Q. Have you applied in this case, Dr. Gringarten, what you

just described, this system of checks and balances, to compare one methodology with another methodology as a consistency check on the reliability of your work?
A.   Yes.
Q.   Let's skip to the last bullet point that says, "Deconvolution." Since we're going to be hearing a little bit more about that in the next few minutes, why don't you describe briefly for Judge Barbier what that is.
A.   Deconvolution is a method -- it's a mathematical tool, and it's a method of processing the data so that you can use all of the data from the test, not a few data points, for obtaining information from the well test.
          We developed that in my team, and that allowed us to see, you know, very far into the reservoir, in fact, to see everything that has been reached by the pressure signal.
Q.   Is that now a standard tool in the petroleum industry?
A.   Yes. It has been -- we developed that tool in the year 2001, 2002. It has been incorporated in all the existing well test interpretation software starting in 2006.
          MR. BOLES: Your Honor, at this time BP would tender Dr. Gringarten as an expert in petroleum engineering and well test analysis.
          THE COURT: No objections. Okay, he's accepted.
DIRECT EXAMINATION BY MR. BOLES:
Q.   Dr. Gringarten, did you prepare a report describing your

calculations and supporting work in this case?
A. Yes.
Q. D-24660, please.
Is this the cover page of your Expert Report?
A. Yes.
MR. BOLES: Your Honor, we would offer Dr. Gringarten's report, which is TREX-11696R, into evidence.
THE COURT: All right, it's admitted.
(WHEREUPON, Exhibit TREX-11696R was admitted into evidence.)
EXAMINATION BY MR. BOLES:
Q. Dr. Gringarten, at a high level can you describe the basic sequence of analysis and work you did to estimate cumulative flow?
A. Well, I have done it in two steps. One is I have calculated permeability from data measured at the reservoir level before the spill. Then I've used that permeability and pressure measured during the spill and during the shut-in following the spill to calculate the rate during the spill from which I could calculate the total discharge.
Q. Let's look at a summary of your opinions on those two stages, D-24661.
Can you summarize for Judge Barbier the opinions you've arrived at in this case.
A. Yes, I've found that the permeability of the reservoir is

238 millidarcies, and that the cumulative discharge of oil is between 2.4 and 3 million stock-tank barrels.
Q. Let's turn first to the first of those opinions, your determination of the permeability of the Macondo Reservoir.
What method did you use to estimate that permeability?
A. Well, I've used well test analysis.
Q. Let's look at an overview of well test analysis at D-23599-1.
What does this teach us about well test analysis, Dr. Gringarten?
A. Well test analysis is a study of the relationship between pressure, flow rates and permeability. In the normal well tests, the flow rates and the pressure are measured, and then you can calculate the permeability. But this figure showed that if you know two of the quantities, then you can calculate the third one.
So if you know the permeability and if you know the pressure, then you can calculate the flow rate.
Q. Let's quickly review what permeability is.
Let's go to D-23596A.
Can you describe for Judge Barbier, what is this property of permeability?
A. Okay. What we have here, we have done two representations of a reservoir that's at the, you know, micro scale. We have

in brown, these are the sand grains. In gray, we have the pore space between the grains.

We have more conductivity in this figure on the right-hand side than we do on the left-hand side. So this reservoir here is less permeable than this reservoir there. The consequence is that the -- permeability characterize how easy it is for fluid to flow through a formation. So it's more difficult to flow -- for the fluid to flow in this in the left-hand side, than it is on the right-hand side.

The rate of production is proportional to permeability. So if you double the permeability, then you double the flow rate. That's the reason permeability is a key to understanding the flow rate.

Q. Is there a name, Dr. Gringarten, in the petroleum industry for this relationship between flow rate and permeability and pressure?

A. Well, the --

Q. Sorry to interrupt you. Let's go to D-23599A.

A. The flow rate, permeability and pressure change are linked by what is called Darcy's law. Darcy's law was developed by Mr. Darcy in 1851. He proved experimentally that the flow rate was proportional to something that he calls the permeability and the pressure differential in the reservoir.

Q. I see you have a little flag emblem there. Where was Mr. Darcy from?

A. He was French.

He developed that study -- he had to study the flow of the fountains in the town of Dijon, which is known for the mustard, and that's how he came up with that relationship, which he found experimentally.

Q. Now, have you worked with Darcy's law in your past work in well test analysis petroleum engineering?

A. Darcy's law is the fundamental law for flow in porous media, so that's what we work with.

Q. Now, Judge Barbier has heard about another fundamental law involved in reservoir engineering called the material balance equation. Can you compare or describe the relationship between Darcy's law and the material balance equation?

A. Material balance is about conservation of mass, which says that if you have a certain volume what comes out is equal to what came in, minus what stays in.

The Darcy's law is more about the flux that goes through the volume. If we take an analogy in finance, for instance, the material balance will be the balance sheet, and Darcy's law would be the income statement.

Q. Now, let's look at how you applied Darcy's law to your work in Macondo, if we can go to the next slide.

How did you use these relationships in starting your analysis of permeability?

A. Well, first, I used flow rate and pressure measured prior

to the spill at the bottom of the well to calculate permeability.
Q. How did you get flow rate and pressure measured prior to the spill at the reservoir?
A. There is a tool that has been used which is called the MDT tool, which was run on April 12th, and which gathered flow rate and pressure through an experiment at the bottom of the well.
Q. Let's look quickly at D-23600.
Does this summarize this next step that you're going to describe with the MDT tool?
A. Correct.
Q. Now, let's have you tell us a little bit about the MDT tool. Let's go to D-23604-1B.
What is an MDT tool, Dr. Gringarten?
A. What we have here is, you know, the schematic of the reservoir. So the brown, the dark ribbon vertical is representing the well. The gold brown horizontal represents the reservoir.
The MDT tool is a trademark of Schlumberger. The general term is wireline formation tester. So that tool is lowered at the bottom of the well with a cable, an x-ray cable, and it's located near at the reservoir. The probe is inserted into the reservoir and --
So initially the fluid is contaminated by the mud during drilling. As you keep pumping, the signal extends into

the reservoir, and the fluid becomes less and less contaminated until you get the reservoir fluid, which is then taken as sample for PVC analysis.

Q. What are we looking at in this zoom-out of that demonstrative?

A. Well, this represent how far the pressure signal has reached in the formation. In the PVC test that I have calculated, we reached about 600 feet, which is about half the distance to the closest boundary of the reservoir.

So the zone investigated is quite large, and, therefore, the permeability we calculated from the pressure and the rate measurements of two are representative of the permeability of the reservoir.

Q. How long does that -- we saw a speeded-up version of that process. How long does that pumping go on in gathering the sample from the reservoir that we just saw represented?

A. Three to four hours.

Q. What's the importance of that?

A. Well, as I said, the longer you pump, the further away the pressure signal goes, and therefore the larger the zone of the reservoir which is investigated, you know, during the test. Therefore, the larger zone is more representative of the permeability you calculate from the data.

Q. Now, what data are you getting from the procedure we just looked at?

Let's go to D-23604-2.

A. Well, what we have at the top here is a graph. Time is on the Y axis. We have pressure on the X axis. So as we pump, the pressure is recorded, and the rate is recorded as well. So in blue we have the pressure versus time as we are pumping, and we have the rate in green versus time.

So this information is being recorded during the pumping, and that's what we use for doing the well test analysis.

Q. This recording of pressure and rate at the same time was done on what date?

A. That was done in April the 12th -- on April the 12th.

Q. Is this the only collection of rate and pressure information taken directly at the reservoir prior to the incident?

A. Yes.

Q. Are you the only expert in this case, up until the rebuttal reports, who used this information to try to estimate permeability?

A. Yes.

Q. Now, let's go -- let's look at the data that is depicted from the MDT test. What data are you going to use there in your analysis to calculate permeability?

A. Well, what we have in blue here is complete recording during the pumping. Whenever the rate decreased, then the pressure goes up.

From time to time, the tool has been shut, and the pressure -- the rate becomes zero, and so the pressure goes up. This is what we call buildup. So there are a number of buildups, which I have analyzed with focus on the very last one.

Q. What does a buildup of pressure do, Dr. Gringarten? I would ask you to refer to the bottom part of this diagram, those pressure signals that you described earlier.

A. Well, the buildup is when the -- you shut the tool. The signal pressure, you know, keeps going on, even during this buildup.

Q. Now let's take a look at another diagram to illustrate how you analyze that pressure signal during a buildup going through the reservoir. D-24676.

Can you describe for Judge Barbier how this representation of a pressure signal gives you information that you use to calculate permeability.

A. Okay. What we -- what we have here is a schematic of the reservoir, so that's the well. Here we have the boundary of the reservoir, so this brown is the reservoir. This is the well.

When we start producing, then the pressure signal goes away from the well. Initially it is, you know, radial, and so we have radial flow. What we look at is the rate of change of the pressure versus time, which is the derivative.

Q. Where is that on that diagram?

A. This is the derivative here, where we plot the derivative versus time. The derivative exhibit the shape, which characterize a reservoir.

So at the beginning, we have something that characterize what is in the well or very close to the well. Then when we develop this radial flow, we have stabilization from which we can calculate the permeability, and then we have the boundary. Where we see those two boundaries, that's this signal here, where there was -- what we call channel flow.

Then, when we reach the end of the reservoir, then we have a different signal here, which we call a closed reservoir.

So the derivative allows us to see exactly, you know, what the reservoir is and how it behaves.

Q. Now, which part of that derivative plot at the bottom of pressure change over time, which part of that plot do you look at to -- in your calculation of permeability?

A. The permeability is given by the flat part here. That's what I have used in my analysis. As a by-product, you know, I get everything, but essentially my objective was to obtain this part here and calculate the permeability.

Q. That's the flat radial flow period?

A. Correct.

Q. Now, let's take a look at that in a simplified way as it relates to your calculation of permeability. Let's go to D-24662.

This is the pictures we had earlier of low and high permeability. How are those then represented in what you look for in the derivative plot or pressure?

A. So these are -- this is the -- on the left-hand side, we have the low permeability reservoir. On the right-hand side, we have the high permeability reservoir.

The shape of the derivative, which we have here and there, are the same. The difference between the two is that the stabilization from which we calculate the permeability would be higher for the low permeability reservoir than for the higher permeability reservoir.

Q. So a lower permeability has a higher radial flow stabilization on the derivative plot?

A. That's correct.

Q. The higher permeability has a lower radial flow stabilization flatness on the derivative plot?

A. This is correct.

Q. Now, let's take these concepts and these simplified plots, and let's look at the actual data plotted as a pressure derivative from this MDT test. D-24665.

Explain to Judge Barbier what this is, Dr. Gringarten, and how you used it to calculate permeability.

A. So what we see here, the triangle in blue represents derivative data. So these are the data of the derivative of one of the tests.

We can see here that the data stabilized in this region. We have something which is flat here. That's what is used for doing the analysis.

The result of the analysis is this red curve here, which -- you know, whereas the flat part goes through the data, and, in fact, it's fitted by nonlinear regression to the data.

Q. Dr. Gringarten, that nonlinear regression that you used to fit that red curve to the data so you can calculate permeability, is that commonly used in the petroleum industry for this kind of analysis?

A. Yes. That's standard in all the well test interpretation software.

Q. That's well test interpretation software?

A. Yes.

Q. How many times in your career have you used a derivative analysis like this and fitting a curve in it to calculate a permeability for an oil company client?

A. The derivative approach has been developed in 1983, and so I've used it since then. It's what you use in doing well test interpretation.

Q. Rough ballpark figure the number of times you've used this method for oil company clients in your consulting?

A. A few thousand.

Q. Now, we can see that there are some blue triangles above and below your red line. What's your analysis of that for Judge Barbier?

A. Well, this represents a scattering of the data. You know, you have better data than that usually, or you could have, you know, worse detail than that. That's not unusual.

So what we can do with that is account for the scattering in the uncertainty analysis, because we could imagine that we could have drawn that red stabilization above the data, and we could have drawn it below the data, and that range, you know, is a range that we can calculate the uncertainty on the permeability.

Q. We'll look momentarily at how you treated that uncertainty in terms of your quantification of permeability, but I want to focus on that scatter that you just referred to. Is that about a scatter around the red line that you fitted to the data, is that something you've ever experienced before in your prior well test analysis work?

A. Yes.

Q. How many times would you say you've seen data plotted in a derivative analysis that has that much scatter?

A. In general, you prefer to interpret data that have a lot less scatter, but you don't have control of that. So, you know, sometimes you have less scatter, you have more scatter. I would say maybe 20 percent of the case, 25 percent of the

cases are, you know, similar to that.
Q. 25 percent of the thousands of cases?
A. Yes, yes.
Q. Now, in the 30 years you've been doing this for industry clients using this kind of derivative analysis and the hundreds of times that you've confronted data of a noisiness or a scatter like this, has any oil company ever come back to you and said, Dr. Gringarten, we found out that the permeability you calculated for us was wrong?
A. No.
Q. What's the first time in the 30 years you've been doing this, Dr. Gringarten, that someone has ever said to you, what Dr. Gringarten has done is wrong?
A. Well, this is the first time with the rebuttal.
Q. Let's take a look at -- what are some of the things you do in addition to quantifying an uncertainty range to give yourself assurance that you fitted the data properly to these derivative points?
A. Well, we compare -- we do the same type of plot. You know, here we have data, and we have a model that we feed through the data. We verify that the same model can match data in different presentations. So we -- in different plots.

So we do a verification process. In fact, the verification process is part of the methodology I established in order to give confidence to both the interpreter and the

person that received the interpretation.
Q. Let's take a look at D-24666. That's slide 21, please.
Is this part of this verification process you described?
A. Yes.
Q. Tell Judge Barbier what this is and how you used it.
A. Well, this is a different way of looking at the data. That's called Horner plot. So these are the same data but presented differently.
We have other plots of the same nature. The verification is to make sure that you can reproduce the -- you know, your model, you know, goes through the data. So, you know, you need to able to reproduce the various plots that you could use and reproduce a derivative as well.
Q. Is there another name for a Horner plot?
A. It's called a superposition plot.
Q. Is it sometimes called a semilog plot?
A. A semilog plot is a simplification of the Horner plot, but it's -- that's what we call it in industry.
Q. Now, we've look at the derivative plot that you said was the more modern method, and now this Horner plot, or semilog plot. What method did your counterpart expert, the rebuttal expert, Dr. Larsen, use when he tried to analyze permeability?
MS. HIMMELHOCH: Objection, Your Honor. This goes to surrebuttal, which you've ruled is improper.

MR. BOLES: I just asked him to identify what the method was that Dr. Larsen used, but I can go at this another way.

MS. HIMMELHOCH: Dr. Larsen can't testify --

THE COURT: Why don't you go ahead. Okay.

EXAMINATION BY MR. BOLES:

Q. Let me ask you this, Dr. Gringarten. Did you consider using only one method, namely, this semilog/Horner plot method, just using that and not a derivative plot as well?

MS. HIMMELHOCH: Your Honor, again, this is an attempt at surrebuttal by redisguising the question.

MR. BOLES: This is discussed in his expert report, Your Honor. At Page 13 of Dr. Gringarten's expert report, he specifically describes, as he mentioned during his qualifications, how the verification is done through using multiple methods, and that the improvements over the generations of well test analysis have come about from using both this kind of older method and the derivative plot.

He specifically discusses that in his report as to why his analysis is more reliable because he uses both methods and uses one to confirm the other. That's on Page 13 of his expert report, for example.

MS. HIMMELHOCH: Your Honor, he does talk about the history of well test analysis. The way the question was phrased, it implies something about the manner in which

Dr. Larsen did his analysis. That was the reason that I objected as surrebuttal.

If he phrases the question as what methodologies did he use or what was the evolution of well test analysis, I will withdraw my objection.

MR. BOLES: I'll rephrase the question, give it one more try.

EXAMINATION BY MR. BOLES:

Q. Dr. Gringarten, why did you choose to use both a Horner, or semilog, method and the more advanced derivative plot when you calculated permeability?

Let's look at D-24667.

A. Okay. As illustrated here, what we have here, Your Honor, we have a log-log plot with derivative, as I've described before. We call that a log-log plot because the pressure and the time are plotted on a log axis.

This is the Horner plot, which, you know, is also called a semilog plot or, more generally, superposition. This is a plot that was developed, you know, in the '50s, in '49 to '51. That's essentially the only analysis tool that was available until the late '70s.

The problem with this tool is that it is very difficult to know where -- how to calculate the permeability. So you could have different permeabilities and still get a good match on that plot.

Q. When you say different permeabilities on that plot, maybe you could make reference to the colors.
A. Yes. Essentially we have three possible permeabilities, the red one, the blue one and the black one, I guess -- okay, yes. So I see it better here. It's red, green and then blue.
Q. Do those represent different permeabilities?
A. They correspond to different permeabilities, and they all match reasonably well the data on that plot.
However, if you look at, on this plot on the derivative, you will see that only the green one matches. The red one gives a permeability which is too low. The blue one gives a permeability that is too high.
You couldn't see that on this plot, but it is very obvious on the derivative plot. That's the reason why, you know, the methodology requires that, you know, you use the derivative not only to identify the stabilization, but also to verify that the model you've used match the derivative data.
Q. Are there any other steps you took besides looking at two different kinds of plots of pressure versus time, any other things you did to confirm or verify the number you were calculating for permeability?
A. Yes. I also used deconvolution, which was developed, you know, in the year 2000, 2001 -- what that does is extend the information.
In other words, the plot we had before represented

03:49:26 the type of buildup, so that's a small portion of the entire test. With deconvolution, then I can get the same kind of derivative but for the duration of the test.

So, for instance, to give an example, with Macondo we had a buildup of 19 days, but we had -- and so the derivative I can get from the buildup will have the duration of 19 days, 1-9, whereas the spill has a duration of 86 days. With deconvolution, then I can get a derivative that has a duration of 86 plus 19 days. So I can see a lot further in the reservoir than I would otherwise, and that allows me to confirm what I see on the buildup and get additional information.

THE COURT: Explain to me again the term "deconvolution."

THE WITNESS: Deconvolution is a mathematical process which, let's say, during a test we have the rate going up or going down. Consequently, the pressure goes up or goes down. Deconvolution will recalculate what the pressure would be if the rate had been constant, in a nutshell.

Therefore, you know, if I have rates going up or going down, I can only do the interpolation for a period was already constant. That's what we normally get to do. So, for instance, usually we use a buildup, and the buildup has a duration which is small compared to the entire test.

With deconvolution, I can convert the entire test into a single throw down, which is equivalent to the buildup, and therefore finds a signature, the complete signature of the system.

EXAMINATION BY MR. BOLES:

Q. Let's follow up on Judge Barbier's question. We have been focusing here on the MDT tool data from April 12th. Let's take the shut-in of the well on July 15th and the buildup that you analyzed from that shut-in period until the data flow ended with the killing of the well.

How did you use deconvolution there to explore the nature of the reservoir and in the way you just described.

A. Sorry, could you repeat the question.

Q. Specifically with respect to the issue of an aquifer, Dr. Gringarten, does this process of deconvolution which you described allow you to reach a conclusion about whether or not there is an aquifer actively supporting pressure in the Macondo Reservoir?

A. Yes, because deconvolution gives what would be the signature of the system for the entire duration of the pressure measurements. So if there is -- so I can see regular flow. As I mentioned before, I could see the lateral boundaries and could see the size of the reservoir because they all give different shapes.

If I have an aquifer, then it would give, you know, a shape which is calculated for the aquifer. So here, I have not seen that shape. So the conclusion is that there is no effect of an aquifer, at least during the data that have been measured.

Q. Now, let's go back to your actual derivative plot for the Macondo MDT tool test from April 12, 2010. Let's look at, again, D-24665.

What did you -- what did you do to quantify the uncertainty around the permeability represented by the red line there?

MS. HIMMELHOCH: Your Honor, I'm not so much objecting as requesting a pin cite for this. I can't find this graph in his report, and I'm just trying to make sure I understand what he's asking about.

MR. BOLES: Well, it certainly comes from the report. I don't have a pin site at the moment, but my colleagues can be looking for that. I'll go on to --

THE COURT: Is this chart from your report?

THE WITNESS: Yes.

THE COURT: Graph?

THE WITNESS: Yes.

MS. HIMMELHOCH: Thank you, Your Honor.

EXAMINATION BY MR. BOLES:

Q. Let's look at how you analyzed that uncertainty with D-24668.

What is this, Dr. Gringarten?

A. Okay, as I said before, I've looked at the upper bound of

03:54:10 the red line and the lower bound of the red line, and that give 03:54:14 me the uncertainty of where to calculate the permeability, at 03:54:19 what level should the permeability be calculated.

03:54:23 I have also taken into account the other 03:54:25 uncertainties, the uncertainty on every parameter that goes 03:54:30 into the calculation. So that's the uncertainty from the 03:54:33 measurement of the pressure, uncertainty on the measurement of 03:54:37 the flow rate, uncertainty in the viscosity and so on and so 03:54:41 forth, all the parameter that I use to, you know, help me 03:54:44 calculate permeability.

03:54:46 To evaluate the uncertainty, I've done a 03:54:50 probabilistic approach, which is using Monte-Carlo simulation 03:54:55 which goes through all the possible values of every parameter 03:55:01 and come up with this result here, which is a, you know, 03:55:04 bell-shaped curve, which gives me the distribution of the 03:55:10 values.

03:55:13 And so the most likely value is the median value, 03:55:16 which is, in this case, 238 millidarcy. And in the oil 03:55:23 industry we call that a P50.

03:55:27 And we give two other values. One is a P90, which is 03:55:31 here, 170 millidarcy. And P90 means that there is 90 percent 03:55:37 chance that the permeability has a higher value than 170.

03:55:42 And the other value that is typically given in the 03:55:44 oil industry is a P10, which says that the permeability has 03:55:50 only 10 percent probability to be greater than this value, which is, in this case, 329 millidarcy.

And this representation, P50, P90, P10, is what typically we do, for instance, for reference.

THE COURT: It looks like a bell curve.

THE WITNESS: That's correct. That's exactly what it is.

EXAMINATION BY MR. BOLES:

Q. Dr. Gringarten, is there an expert in this case who used the higher number of permeability indicated by your analysis, the P10 value of 329 millidarcies in his analysis?

A. Yes. Professor Blunt, who has already testified, he's a BP expert, has used my value of 320 millidarcy.

Q. Now, this method that is resulted in this calculation you've just presented of permeability, using the MDT tool, is that used in the industry as a way of calculating permeability?

A. Yes.

Q. Have you published an article about the increasing use of wireline formation tests for calculating permeability?

A. Yes.

Q. Let's look at D-24689.

Is this your article, Dr. Gringarten, or the first page of it?

A. That's correct.

The title is *Will Wireline Formation Test* -- which is what we are looking at here -- *Replace Well Tests?*

Q. Now, in addition to Schlumberger, who makes the MDT brand of a wireline formation test, are there other service companies in the oil industry, Dr. Gringarten, who make a similar tool and are now marketing it to oil companies as a way of determining permeability?

A. Yes. All the service companies, Halliburton, Baker, Weatherford, they all have their version of what we see here.

Q. And is the MDT analysis that you've done the only analysis of permeability in this case that uses known flow rate data and known pressure data from before the incident to calculate permeability?

A. This is correct.

Q. Now, let's look at a summary of the permeability numbers from the various experts in this case, D-23603.

Can you summarize, Dr. Gringarten, the numbers used by other experts in the case and the method they've used?

MS. HIMMELHOCH: Objection, Your Honor. This demonstrative clearly sets forth surrebuttal since it includes a discussion of Dr. Larsen's work.

MR. BOLES: It's very brief, Your Honor, and I think it would provide a helpful overview to the Court.

THE COURT: Okay. I sustain the objection.

EXAMINATION BY MR. BOLES:

Q. Let's move on then.

Dr. Gringarten, what would be your opinion of any

expert analysis that did not tie its cumulative flow calculation to a known permeability?
A. Well, the permeability that I've calculated is permeability of the reservoir, so that's something we know. And in a flow rate, when analyzed with the available pressure measurement during the spill and the subsequent shut-in, have to come up with that permeability. So there is -- the flow rate cannot be independent of the permeability.
In other words, this is a triangle that we -- was shown before. You know, if you have the pressure and if you have the flow rate, then you should get the permeability of the reservoir. And so in a flow rate that doesn't give the permeability of the reservoir, it cannot be correct.
Q. Now, the United States' expert Dr. Pooladi-Darvish, not a rebuttal expert, uses permeabilities that vary widely from 360 millidarcies to 850 millidarcies.
What have you said in your expert report, Dr. Gringarten, about that approach by Dr. Pooladi-Darvish?
A. Well, Dr. Pooladi-Darvish, you know, is -- in his simulations, is not only changing the permeability, but is also changing at the same time a number of other parameters.
And so, therefore, you know, what he -- he's using a range, which is, you know, outside the range of possibilities. And his range should -- you know, when you use -- pressure, should, you know, provide the same permeability as I've

obtained.

Q. Now, Dr. Gringarten, let's turn, and more quickly now, to the second part of your analysis, which is using the permeability that you just showed us how you derived, and Macondo pressure history to recreate the flow rates and thereby estimate the cumulative flow.

Let's go first to D-23601A.

Let's review again that triangle of relationships from well test analysis and describe what you're going to do now in the second part of your work.

A. Well, now we have -- you know, from the first part, we have the permeability that we have obtained from the MDT. That's from down measurements. And we have pressure measurements, which have been taken during the spill. And we have also pressure measurements, the initial pressure obtained from the MDT on April 12th. And so now I have the pressure and the permeability, and therefore, I can calculate the flow rate.

Q. And what is the process that you used, Dr. Gringarten, to take the pressure history in the lower left-hand corner of that triangle and reconstruct the unknown flow rate of Macondo spill? What's the method you used?

A. Well, I've used the deconvolution.

Q. Now, Doctor -- Judge Barbier asked you about deconvolution earlier, and you gave one application of it in the oil history. Let's look at how you are going to use it here, D-23608A.

That's Slide 36.

Describe how this analogizes to how you use deconvolution to reconstruct flow rates.

MS. HIMMELHOCH: Objection, Your Honor. Relevance. This refers to the use of a mathematical concept in an entirely different industry. Irrelevant to the matter at hand.

MR. BOLES: It shows the use of the very same mathematical algorithm, and by analogy, how the fuzzy or unknown data in the left-hand picture can be used to derive a very clear picture, in this case, of the historical Macondo flow rates.

I don't believe this was objected to when we submitted this to you some days ago.

MS. HIMMELHOCH: I'm objecting now to the testimony, Your Honor. There is a distinction between the use here, which is to sharpen an existing image, and the use that Dr. Gringarten made, which was to create a rate out of information that he claims does not exist. That is the basis for my objection.

THE COURT: Is this all in his report?

MR. BOLES: This description of the use of deconvolution to take information and extract the maximum value from information that would be unclear without the use of this algorithm is discussed repeatedly in his report, so this is -- to help explain that, we're using by analogy.

THE COURT: It talks about comparing this to Hubble?

MR. BOLES: I don't believe the Hubble telescope is specifically mentioned in his report. This is an illustrative analogy.

MS. HIMMELHOCH: It is not discussed, Your Honor.

THE COURT: I sustain the objection.

EXAMINATION BY MR. BOLES:

Q. Let's move on from this image, then.

Dr. Gringarten, describe how you used deconvolution to reconstruct the historical flow rates of Macondo. And let's look at Slide 40, D-23620A. Slide 40.

A. Okay. The first step is I convert the wellhead pressure to downhole pressure. And I do that because the downhole pressure is more representative of the reservoir than the wellhead pressure. And then I used deconvolution to create rates that are compatible with these downhole pressures.

So I start with the rate, let's say, which is constant, and then I apply deconvolution, and that is a rate that I obtain, which is compatible, consistent with the pressure. And so I do several iterations of deconvolution until I get a final rate, and I verify that if I use that rate, then I can reproduce the pressure, which I've started from.

Q. Dr. Gringarten, can you describe for Judge Barbier other instances in the oil industry when deconvolution has been used by you or others to correct or recreate rate information that

was unknown or unclear?
A. Yes. Deconvolution, well, is used -- as I said before, was developed in 2000, 2001. In fact, people have been working for the last 20 years but never came up with a stable algorithm.
And so what deconvolution does, it does two things: Number one, it gives a complete signature of the system for the duration of the test, and it allows to correct rates that are erroneous, like which is often the case, or it can allow you to calculate rates that are missing.
And to calculate rates that are missing, then you assume a rate, which is arbitrary, and then you do the deconvolution. The deconvolution is going to readjust that rate to the actual pressure measurements. So if you have pressure measurements, then you can correct the rates.
Q. And is that process you described with taking either an arbitrary starting rate or other flow rate information and correcting it, either -- by using that deconvolution algorithm, is that something you've done for consulting clients in the oil industry?
A. Yes. That's something you do routinely. In the same way as we always use the derivative now for analysis, we always use deconvolution. Deconvolution gives more information and corrects the rate that you start with.
Q. Has any other expert in this case used deconvolution to

04:08:03 try to reconstruct historical flow rates from Macondo incident
04:08:06 from the pressure history?

04:08:07 A. No.

04:08:07 Q. Now, Dr. Gringarten in this process that you described of reconstructing or correcting a flow rate from the pressure history, can that deconvolution process detect changes in impediments to flow below the pressure measurement gauge?

04:08:29 A. No. Because one of the assumptions -- well, the -- what deconvolution does, it looks at the change in pressure from one point in time to the next, and it attributes that change in pressure to a rate. So there is no impediment to flow. This is a process which is separate from what is pure processing of the data.

04:08:59 Now, if there is an impediment to flow, deconvolution cannot see that, and it would, therefore, come up with a rate that would be too high compared to what it should be, you know, if there is an impediment to flow.

04:09:16 Q. Now, are you in this case, Dr. Gringarten, offering any opinions on erosion of impediments to flow in the Macondo well over time?

04:09:26 A. No, I'm not.

04:09:27 Q. Why is that?

04:09:28 A. Because my focus -- well, number one -- two reasons. Number one, my focus was on the permeability because that's what I need to calibrate the rate that I calculate from the deconvolution. And the only impediment or skin that I can calculate with confidence is the one that I can calculate from the buildup, which is, you know, what we have here at the end.

Q. And when does that begin?

A. That begins on July 15th.

Q. Now, let's look at a road map, I believe this is Slide 46, of your -- of your analysis. And this is all in your report, so we're not going to go into it in detail.

But you've just spoken to us about -- let me get my own pointer here -- taking the pressure history and using the process of deconvolution to extract information to reconstruct the rate history. And we're going to now ask you to describe what you do once you get that relative rate history.

And, first of all, what do you mean by *relative rate history*?

A. The -- what I can calculate from deconvolution is, you know, the successive rates relative to one another, so I cannot calculate an absolute value. I calculate the Delta Q, the change in rate that would create the change in pressure.

In normal well tests, there are, you know, unknown -- there are errors in the rates, but usually we have one rate or a few rates that we trust. And therefore, we are going to calibrate the relative rate history on those rates.

Here, we do not have a rate that we can, you know, rely upon, so what we do is we -- I take this rate history, relative rate history, and the pressure history and I do a well test analysis. The well test analysis gives me permeability, and then I compare that permeability to the permeability I know for the reservoir, which I've obtained from MDT analysis.

And if they are different, then I address -- you know, multiply the relative rate by a factor which is such that -- which is a ratio of what I obtain here in -- you know, in the analysis with that rate with the MDT permeability, so that I can correct that rate and obtain the same permeability from the analysis that I did from MDT.

Q. Now, we'll look at the -- how you do that in a minute, but let me just ask you in this summary road map of your work, the two blue boxes with the gears next to them, what do they represent?

A. They represent two steps in the process. One is the processing of the data, deconvolution. And the other one is the analysis of the data.

And so what this does, it makes the rate history consistent with pressure. And what this does is, you know, with this final result on the rate history, is to make the rate history consistent with the reservoir permeability.

Q. Now, do you use software for these two steps showing in the blue boxes with the gears?

A. Yes.

Q. Is the deconvolution software separate from your well test analysis software?
A. In my case, yes. Some of the commercial software have the two integrated.
Q. Now, we're about to describe this penultimate step of the well test analysis. Does that analysis take as an input the relative rate histories from the deconvolution?
A. Yes.
Q. And do -- are those the rate histories that you described earlier that cannot convey information about historical changes and impediments to flow in the wellbore?
A. No.
Q. I may have put a double negative in my question.
Do the rate histories that deconvolution delivers to the well test analysis software have any information about the changes in impediments of flow over the history of the incident?
A. No.
Q. Now, let's look at what you do with a well test analysis and let's look at a couple of outputs from that second software, the well test analysis software, D-24696, Slide 44.
What is this step in your analysis, Dr. Gringarten?
A. Well, this is a summary in terms of graphs of the analysis, and there are two parts here. If we look at the graph on the left-hand side, the first two -- you know, the

starting point is this graph, which is a normal graph, which is pressure and derivatives.
Q. You're referring to the upper left-hand graph.
A. Correct.
Q. What is that called?
A. This is called the log-log diagnostic plot. That's where we select the various regime and, in particular where we're going to calculate permeability.
Q. Can you relate that to something you've already talked about in the permeability part of your work? Is this the derivative plot?
A. Yes, this the derivative. I thought I mentioned it, yes.
Okay. And here, you know, we have a flat part. That's where we calculate the permeability. And we verify that we have, on the Horner plot, a straight line from which we calculate permeability, so this is a verification.
And then we generate a model, and we make sure that the model fits, you know, match all the data. So here we match the pressure. We match the derivative, and we match, you know, the Horner plot as well.
And the last plot here is we take the model and then we compare with the pressure that has been measured during the spill, and any mismatch between the pressure and the model is attributed to the skin effect, which is represented here.
Q. Are these graphs we see, are these standard displays built

into the software?
A. Yes.
Q. Let's look at the -- in the lower left-hand side, what is it that you -- did you -- how did you use the skin versus time plot in the lower left-hand panel of this software dashboard?
A. Well, we verify that we end up with results that are reasonable, can be explained, especially that there is no value which is unphysical. For instance, if we would come up with a skin less than minus 4, that doesn't exist, so that means something is wrong in the analysis.
Q. What about the right-hand side of that graph? Was that something that you used?
A. This one here?
Q. Yes. The right-hand end of the --
A. This is the skin obtained from the buildup. And this is calculated by -- you know, from the analysis. This one here is simply an expression of the mismatch between the data and the model.
Q. Now, in the flat part of that skin versus time graph, if we were to be able to see the timeline, it reflects May 8th to July 15th, does that tell you anything about what is physically happening in the wellbore in terms of impediments to flow?
A. No. Not really. Because this is obtained from the mismatch. So that's -- you know, the value that we need -- I have indicated that in my report, is what you need to -- for

the model to match the data.

Q. Now, let's look at the result of this well test modeling and what you do with it with respect to the relative flow rates that you derived from deconvolution.

Let's go to Slide 47, D-24222.

What are we looking at here, Dr. Gringarten?

MS. HIMMELHOCH: Objection, Your Honor. This mischaracterizes Dr. Dykhuizen's flow rate analysis.

Also, this graph, as it appears here, does not appear in Dr. Gringarten's report.

MR. BOLES: The rate curves do, and to aid the Court to show how this relates to --

THE COURT: I'll overrule the objection. And if you want to cross-examine him on the accuracy of it, you can do that.

MS. HIMMELHOCH: We'll do so, Your Honor.

THE COURT: Go ahead.

What was your question for the witness?

EXAMINATION BY MR. BOLES:

Q. Describe for Judge Barbier this result of your well test analysis using your deconvolved flow rates.

A. Okay. I have considered different case in converting from wellhead pressure to bottomhole pressure. Wellhead pressure is the PTB pressure and the capping stack pressure during the shut-in.

Then I considered several flow paths, in fact, two flow paths in the well, and the calculation has been made with the multiphase flow simulator by Dr. Johnson, who was a BP expert, and I end up with the blue curve, which correspond to my permeability of 238 millidarcies.

So this is the flow rate for one of the case, which is the most likely case, corresponding to the P50 permeability obtained from the MDT.

Q. When you say *most likely case*, just to clarify, that refers to what, Dr. Gringarten?

A. Most likely means that I am consistent with the range of flow that were given between May 13th and May 20th by Dr. Zaldivar from his fluid flow calculation.

And here I -- you know, I used the range of flow before shut-in that were given by another BP expert, and I'm slightly below the value that was given by that expert.

Another flow possibility, you know, with the same configuration is this flow rate in green, which, you know, matched around 45,000 barrels at the time of shut-in and still goes through the range given by Dr. Zaldivar. This does not correspond to the P50 probability of 238. It requires a permeability slightly higher, which is 281, which would correspond to P35.

Q. Was that green permeability that you scaled the rate to in that most likely case, was that one of the permeabilities

within your range of possibilities that you analyzed?
A. Yes. It's between the P50 and the P10. It's around P35.
Q. Let's look at the cumulative flows that you calculate from these two possible rate histories, including the most likely rate history with the P50 permeability.
Let's go to Slide 48, D-23622.
Now, relate that to the two curves we just looked at, Dr. Gringarten.
A. This number here, 2.5 million stock-tank barrel corresponds to the permeability of P50, so that was the blue curve on the previous slide.
This corresponds to a rate of 45,000 stock-tank barrel per day at the time of shut-in, and so that correspond to the green curve.
And so this one gives me cumulative discharge of 2.5 million stock-tank barrel. This gives a discharge of 3 million stock-tank barrel.
Q. And let's go to Slide 49, D-24223.
Which is other cases that you looked at that you called Option 2 for a different starting flow rate in your pressure translation, and two different configurations of the wellbore.
Describe what you determined with respect to cumulative flow using your P50 permeability and with a higher permeability that would scale those flow rates to an ending

flow rate of 45,000 stock-tank barrels per day.

A. Well, these are two options, as I've indicated. I've used a range of downhole pressure to cover, you know, the range of uncertainty. And so these are two other cases that give me -- for the P50, which means they correspond to the 238 millidarcies. And this one, you know, that gives a range of 2.4 to 3 million stock-tank barrel.

And, you know -- you know, the case, but they don't give 45,000 stock-tank barrel per day at the time of shut-in, so to get 45,000 stock-tank barrel at the time of shut-in, then I need higher permeability and this gives me 3.3 million stock-tank barrel in terms of total discharge.

Q. Dr. Gringarten, I would like to end by just having you describe what -- for Judge Barbier your -- you read Dr. Blunt's expert report in this case?

A. Yes.

Q. And what is your opinion of his work?

MS. HIMMELHOCH: Objection, Your Honor. They did not provide an analysis of Dr. Blunt's report and his opinion of Dr. Blunt's report in Dr. Gringarten's report.

MR. BOLES: Well, he does say that he approves of Dr. Blunt's work. And counsel for the United States has repeatedly asked their experts to compare methods used by their various colleagues on the same side of the case in order to help illustrate to the Court the advantages and disadvantage of different methods, so I think it would be helpful to the Court.

MS. HIMMELHOCH: Your Honor, he does indicate that he reviewed Dr. Blunt's conversion of capping stack pressures, which is a direct input into his analysis. But he does not provide a general endorsement or analysis of Dr. Blunt's opinions.

THE COURT: Well, I don't remember with the other witnesses whether the issue came up. Again, is this something that's in his report or not?

MR. BOLES: Just to go to the one point you mentioned, Your Honor, that Dr. Kelkar was the one that they asked to elaborate on and explain the advantages and disadvantages of his material balance analysis compared to the analysis done by other United States experts, which wasn't in his report.

MS. HIMMELHOCH: If they will allow the same of our rebuttal witnesses, I will withdraw my objection.

MR. BOLES: In answer to your other question, Your Honor, the reference to Dr. Gringarten's report and his discussion of Dr. Blunt is on page 35 of his report, where he says that, "Dr. Blunt used a different methodology to analyze the Macondo Reservoir and the cumulative flow. I've reviewed his report and approve his analysis."

So I would like to ask him to explain that.

THE COURT: All right.

MS. HIMMELHOCH: I apologize for the mistake, Your Honor.

THE COURT: I'll let him. Go ahead. Overrule the objection.

BY MR. BOLES:

Q. So, Dr. Gringarten, does your analysis directly use as an input rock compressibility?

A. Not for the purpose of the result that I give. In other words, the compressibility has no impact on my permeability. It would have an impact on the size of the reservoir that I calculate because as the start of the analysis I calculate a number of things. I calculate the size of reservoir, I calculate the average reservoir pressure and so forth; but, for answering the question that I was asked to answer, I only used permeability, and the permeability is independent of compressibility in my technique.

Q. In terms of the relative uncertainties or advantages and disadvantages of your analysis that we've just reviewed using well test analysis and deconvolution in particular to reconstruct the flow rates during the incident, and Dr. Blunt's material balance analysis, which doesn't require that, can you describe for Judge Barbier your opinion as to the relative advantages and disadvantages and uncertainties?

A. Well, these are two different approach to trying to come to the same result. This is not unusual in the oil business because we are dealing with uncertainty. So we try to have redundancy and try to arrive at the same result by different -- the same result by different methods. You know, you don't get the same result, but you get, you know, a range, and the range hopefully overlaps.

In terms of my technique, of course, you know, I rely on the pressure during the spill. The advantage of method of the material balance used by Dr. Blunt is that he doesn't have to do that. You know, he has data before the spill, and then he has data in the shut-in after the spill.

So he has, you know, only three variables. Therefore, I must admit that he has less uncertainty that I do to deal with. So, you know, if we have to select one, maybe his is more -- you know, is less uncertainty. Also, my results back up his results. I stand by my results, obviously.

Q. Dr. Gringarten, in your -- in those cumulative flow numbers we just saw, what method did you use to convert from the reservoir volume to the surface volume, or stock-tank barrels?

A. I used the formation volume factor that was provided in his table by Dr. Curtis Whitson.

Q. What method was used to come up with that formation volume factor?

A. The single-stage flush.

Q. I just want to --

MR. BOLES: I'm almost done, Your Honor. I have a couple of points that I forgot.

I don't think I mentioned for the record that when I was -- when we were looking at the standard dashboard of graphs from the well test interpretation software, that was demonstrative D-24697.

BY MR. BOLES:

Q. I didn't really plan it this way, Dr. Gringarten, but I actually forgot to ask you about your awards and recognitions in the field, so let's end there.

Let's go to slide 6, D-23618.

I'm not going to go through all of those, but, Dr. Gringarten, that second bullet point, that you've been recognized by the SPE as one of the legends of the petroleum engineering industry this past year.

First of all, what is the SPE?

A. The SPE is the Society of Petroleum Engineers. It's a professional society with about 110,000 members around the world.

Q. Of those 110,000 members present and many more past, how many of them have received this designation as one of the legends in the petroleum industry?

A. I think, less than ten.

Q. What does that signify?

A. Well, this is to recognize people that have -- for their entire contribution to the industry, and to just acknowledge the legacy of their contribution.

MR. BOLES: Thanks, Dr. Gringarten.

MS. HIMMELHOCH: Good afternoon, Your Honor. Sara Himmelhoch on behalf of the United States. May I proceed?

THE COURT: Yes.

CROSS-EXAMINATION BY MS. HIMMELHOCH:

Q. Good afternoon, Dr. Gringarten. It's good to see you again.

A. Good afternoon.

Q. I want to begin by talking a little bit about that last half of your testimony which was how you calculated your cumulative volume of oil released.

Now, you started that calculation by assuming flow rates; isn't that correct?

A. That's correct.

Q. Then you used deconvolution to match those assumed flow rates to the pressures measured at the PT-B gauge, which is on BOP, correct?

A. Yes. That's the starting point, yes.

Q. Then from there, Dr. Johnson took your flow rate history and converted it -- converted the PT-B pressures to bottomhole pressures, correct?

A. Yes.

Q. From that point forward, any flow rate history matching you did was to those converted bottomhole pressures; isn't that

correct?
A. That's correct.
Q. In other words, from that point on, you took as bottom -- as ground truth the bottomhole pressures that were calculated from that assumed flow rate; isn't that correct?
A. What I have obtained is a range of downhole pressure. The purpose of getting a range is to take into account the uncertainty, you know, in the data and in the conversion.
So I tried to cover a range that would seem reasonable, and therefore would give me, you know, a reasonable range of, you know, total discharge.
Q. I think my question was not clear, so let me try it again. You took that converted downhole bottomhole pressure range as your ground truth against which for future flow rate matching you used that bottomhole pressure, correct?
A. Yes.
Q. That bottomhole pressure was calculated from your assumed flow rate, correct?
A. Yes.
Q. Okay. Let's move on to another aspect of your deconvolution procedure. You applied your methodology to these two different options, which we'll call Option 1 and Option 2, as you did in your report, correct?
A. That's correct.
Q. Option 1 assumed a consistent 45,000 stock-tank barrels

per day during this spill; isn't that correct?
A. Yeah, as a starting point, yes.
Q. Option 2 assumed 30,000 a day until May 31st, and then 45,000 thereafter, correct?
A. That's correct.
Q. Now, using those two different starting points, you got two different answers, didn't you?
A. Yes. Well, there is a step in between, which is, you know, I take these two starting values, and I make them consistent with the pressure, the wellhead pressure, with deconvolution.
So I end up with two rates of distribution that are simply, you know, a multiplication of one -- you know, they are off by a multiplication factor.
Q. Right, but matching the same pressures with different --
A. That's right. Therefore, they are the same shape.
Q. They have the same shape, but using the same pressures to match, you got from your Option 1 a cumulative flow of 2.49, and from Option 2 a cumulative 3.0 million stock-tank barrels; isn't that correct?
A. That's correct.
Q. So using different starting points, you wound up with different cumulative volumes of oil released?
A. Yes, and that's called a range.
Q. Right. But both of those curves were supposed to be

04:34:56 matched to the same set of pressure data; isn't that correct?
04:34:59 A. I'm not sure what you mean by that.
04:35:00 Q. In order to complete your deconvolution process, you took your assumed flow rate and adjusted -- deconvolved them against the bottomhole pressures that Dr. Johnson calculated?
04:35:11 A. Yes, once I got the bottomhole pressures, yes.
04:35:14 Q. You used the same bottomhole pressures to deconvolve your Option 1 as you did to deconvolve your Option 2?
04:35:22 A. I'm confused.
04:35:26 Q. You deconvolved a flow rate history derived from Option 1, correct?
04:35:32 A. Yes.
04:35:33 Q. You deconvolved a flow rate history derived from Option 2?
04:35:37 A. Yeah, before conversion I used --
04:35:40 Q. Both before and after. Didn't you deconvolve them twice?
04:35:44 A. Yes.
04:35:45 Q. At the top, and then you got a bottomhole pressure?
04:35:47 A. The first deconvolution was to get the rate which Dr. Johnson could use in his multiphase simulator. Those rates differ by a multiplication factor.
04:36:01 So the idea here is to have a range of bottomhole pressures that would represent the possible range of what did happen because we didn't measure.
04:36:13 So once I have the bottomhole pressure, you know, then I start again. You know, I, as you say, consider his

bottomhole pressure as representative. Then I calculate the rates by deconvolution from these bottomhole pressures.
Q. Now, using the two different flow rates but the same pressure data, you arrived at two different flow rate histories, as you've just said, correct?
A. Not from the same pressure data. You know, once I have pressure -- that's something, you know, I'm missing here. Once I have -- you know, I have four bottomhole pressures.
Q. Yes.
A. So for each bottomhole pressure, I'm going to recalculate a rate which is consistent with that bottomhole pressure.
So there are -- you know, so for each pressure, I do the conversion. For each bottomhole pressure, I get a rate which is consistent with that bottomhole pressure.
Q. Now, the deconvolution you do at the bottomhole, after you've converted the pressures down at the bottomhole, what you're attempting to do in that deconvolution is to minimize the difference between the measured value and the calculated value; is that correct?
In your deconvolution process, you're trying to the minimize the difference between your measured pressure --
A. The verification -- you know, you do deconvolution.
Q. Yes.
A. That for a given bottomhole pressure, you know, one case. You get the rate history. You verify that the deconvolution is

consistent by recalculating the rate with that pressure -- you know, with that rate that you -- and then comparing with the pressure you have started from.

Q. Correct.

A. So you do a number of iterations until you get, you know, almost perfect match.

Q. When you did your deconvolution at the bottomhole against your bottomhole pressures, you obtained a different flow rate profile than you had when you did the deconvolution at the top of the well; isn't that correct?

A. That's correct because these are two different things. One is for getting downhole. The other is when downhole, you know, to what would be downhole.

You know, the purpose, again, is to have a range of pressure downhole that would cover a possibility, and then you start from there.

Q. Once you've deconvolved it downhole, those flow rates are more accurate in your view; isn't that correct?

A. There are -- those rates represent -- you know, what -- these rates are consistent with downhole pressure.

Q. Yet you didn't go back and readjust your downhole pressure based on these new flow rates, did you?

A. Because there is no point. I mean, they would never converge.

You know, if you look at the well, you know, normally in oil wells, we measure systematically is wellhead pressure, and, you know, in normal well tests, we have also downhole pressure.

The wellhead pressure and downhole pressure are different. For instance, here we have single phase at the bottom of the well, we have two phase at the top of the well. The pressure profiles are completely different, so there is no way that by this over here you're going to have the same deconvolution by deconvoluting the wellhead pressure and deconvoluting the bottomhole pressure. So, you know, there is no point in trying to do it because you'll never converge by definition.

Q. Do you recall testifying in your deposition that the reason you did not go back and reiterate is because the value would have landed in between the two flow rate profiles?

A. Yes, and --

Q. That's the answer you gave at your deposition, correct?

A. No. Well, if I recall, you were talking about why didn't I use a higher -- you know, why didn't I start with 60 -- 50 or 60,000 barrels at the very beginning of the process.

Q. I'll move on and come back to this when I find my deposition cite.

Now, you agree there is only one set of PT-B pressures, correct?

A. Yes.

Q. You deconvolved two assumed rates to those PT-B pressures and got two different rates; isn't that correct?
A. Yes, by definition. You know, as I have explained in the direct part of my testimony -- may I -- what you get from deconvolution is the relative rate.
So if I start with a higher rate, then I'm going to have, you know, a higher deconvolved rate. So, of course, in the process which I did downhole, I had just the relative rate to the permeability. You know, if I were to do that with the deconvolution at the wellhead, I would get only one rate history because it would be adjusted to the permeability from MDT, but that's not what I'm trying to do here. I'm trying to have a range of downhole pressure.
So I start with, you know, the range of the one -- you know, a rate history which allows me to do that.
Q. Can I just -- you've given your explanation, but let me just make sure it's clear on the record.
When you deconvolved two assumed rates to the same PT-B pressures, you got two different flow rates, correct?
A. Of course. They have the same shape. That's very important. They are shifted, you know, by the ratio of the cumulative production that these two rates represent.
Q. Let's go to TREX-011696R1 -- I'm sorry, 37.1.US, please. This is your deconvolved rates at top hole, correct?
A. That's correct.

Q. The shape of these curves is the same, correct?
A. That's correct.
Q. But they are different values; isn't that correct?
A. Yes.
Q. Those were deconvolved using the same pressure, correct?
A. Yes, absolutely. That's the reason why they are the same shape.
Q. Now, let me just confirm another fact that wasn't talked about in your direct but I think is clear. You did not use any of the information regarding the amount of fluid that was collected or the amount of oil that was collected after the insertion of the Riser Insertion Tube Tool and the other collections method that were used?
A. No.
Q. You didn't use them, in fact, because you said that the collection rates were a small fraction of what was released; isn't that correct?
A. That's what I said, yes.
Q. In your opinion, therefore, 810,000 barrels was a small fraction of what was released; isn't that correct?
A. Yes.
Q. Okay. Let's move on to another point that has been made by your counsel in questioning of the government's witnesses, and that is this question of a day-by-day calculation.
Let's call up TREX-011696R.0053.1.US.

This is a graph from your report, is it not, sir?
A. Yes.
Q. This shows that in your analysis what you do is you come up with a daily flow rate, and then you sum that to come up with your cumulative volume of oil released, correct?
A. Yes.
Q. In the words of Mr. Brock -- I almost gave you doctorate, Mr. Brock -- in the words of Mr. Brock, therefore your analysis is a day-by-day calculation, isn't it?
A. Yes.
Q. Okay. Let's go on to talk a little bit about the pressures that you used. I want to focus for this time period on the period before May 8th.
The calculated rates that you use are dependent on the pressure measurements that you have, correct?
A. Yes.
Q. You have agreed, have you not, that the PT-B pressure data that began on May 8th can be used reliably as part of an estimate of the cumulative volume of oil released, correct?
A. Yes, I think I've said that, you know, I calculated the rate from these pressure measurements, and then I summed them up.
Q. You specifically agreed with me at your deposition that these pressures can be used reliably as part of an estimate of the cumulative volume of oil release, didn't you?

A. Yes.
Q. But prior to May 8th, we don't have the PT-B pressures, correct?
A. Well, we have one pressure at Time Zero, you know, when the -- which is the pressure converted to wellhead that we obtained from the MDT on April 12th. So we have one point.
Q. Please forgive me, but I asked a much more specific question. Prior to May 8th, we don't have any PT-B measurements; isn't that correct?
A. We don't have PT-B measurements, but we have something -- you know, we -- that doesn't mean that we don't have a pressure because we do.
Q. I'm going to get to that. So what you did to pick your pressure to start your pressure curve was to take the initial reservoir pressure calculated during the MDT test, correct?
A. Correct.
Q. You agree with me, do you not, that that is a shut-in pressure? The well was not flowing at the time that that pressure was taken, correct?
A. True.
Q. It is not a flowing pressure, it is a shut-in pressure, correct?
A. Well, it is an initial pressure.
Q. A shut-in pressure, correct? The well was shut-in at the time the pressure measurement was taken?

A. Well, the well was not flowing because that's an MDT measurement.
Q. You agree that what you did with respect to your pre-May 8th data was to take the point of the shut-in pressure measured before the explosion and draw a straight line down to the May 8th pressure measured at the PT-B gauge, correct?
A. Yes. I mentioned, also, I think, that that may not be, you know, exactly correct. The true would be a little more concave, but it wouldn't be that much different.
Q. May I please have the ELMO for a moment.
Dr. Gringarten, I've put on the ELMO an excerpt from your report, which, for convenience sake, I have marked as D-21770.
THE COURT: He says can you move it over a little?
BY MS. HIMMELHOCH:
Q. I'm sorry, I absolutely can. Does that work better, sir?
A. Yes.
Q. This is a plot of your BOP datum pressure against your assumed pressure, correct?
A. That's --
Q. Or your assumed pressure and the datum points from PT-B gauge, correct?
A. Well, all of these are the PT-B gauge except for the first point. Then the red line represent the interpolation between points, neglecting the Top Kill --

Q. So what we're focused on right now is the part of this curve that starts right near the Y axis and extends down to May 8th, correct?
A. Yes.
Q. You indicated, as you said here and as you did in your deposition, that, in fact, that curve could be more concave; could it not?
A. It wouldn't be concave like this. It wouldn't go out.
Q. Yeah, I went too far down. But it could be --
A. It would be slightly more concave.
Q. Like that? It could be like that?
A. No, I don't think so. It would be, you know, less concave. In other words, you know, the belly of that, you know -- it would go more directly from the first point to the last point.
Q. So something like this?
A. Yes.
Q. I'm going to call that Gringarten line. Okay?
A. Uh-huh (affirmative response).
Q. So if you had used that more concave line, you would have had an additional flow during that time period, correct?
A. I would have, yes, at the higher rates.
Q. You would have had a higher flow rate for the period before May 8th, correct?
A. That's correct.

Q. If you had a higher flow rate during the period of April 20th to May 8th, you would have had a higher cumulative volume of oil released, correct?
A. A slightly higher cumulative because the increase in cumulative wouldn't be that great. It would be, you know, a few percent.
Q. That's if you accept your line, which I've labeled the Gringarten line, correct?
A. That's correct.
Q. But you present in your report no analysis for selecting the Gringarten line as opposed to what I've labeled the US line, do you?
A. No. But, taking, you know, a different interpolation is reasonable, and I think I heard Dr. Griffiths do the same, if I recall.
Q. You did not review Dr. Griffiths' report?
A. No, but I was sitting there when he made his presentation.
Q. But you did not present in your report an analysis that gives a basis for choosing between the Gringarten line and the US line, did you?
A. No. I said simply, you know, I took the interpolation.
Q. If you had accepted even your line, your cumulative volume of oil, release would increase; would it not?
A. Yes, but by a small percent.
Q. If you used what I call the US line, it would be a greater

percent, correct?
A. Yes. I mean, you can, you know, do all the assumption.
You have also to look at, you know, how that would affect the permeability that you have to get at the end.
Q. I understand that in your methodology you have to scale to permeability, but still, if you start with a higher flow rate, even if you're scaling to permeability, you will wind up at the end with a higher cumulative?
A. Yes, it's a question of how much.
Q. You don't have any basis for saying how much?
A. No.
Q. Okay. Let's talk a little bit about a concept called Skin. As I understand it, Skin is a measurement of the resistance to flow between the reservoir face and the well, correct?
A. And where you take the measurements.
Q. Okay. Let's go to TREX-016696R-N.0045.1.US. This will require -- thank you.
This is a chart that we saw just a few moments earlier in your direct examination, correct?
A. Correct.
Q. What you show here on this graph is that between May 8th and the end of the spill, your Skin is small and rather constant; isn't that correct?
A. Yes.

Q. In your deposition, did you not acknowledge that that analysis therefore shows that there were no significant changes in the wellbore between May 8 and the shut-in of the well?

A. If I recall, you said that -- and I concurred that it implied that there was no change in the wellbore. However, as I said in my direct, this part, you know, between May 8th and July 15th -- and I mentioned that in my report -- is really the result of a fit between the model and the data. It is by default in the software attributed to the Skin because normally you know the rate, and so the only other possibility is the Skin, but it could be also due to the rate.

So I don't really -- the only thing what I can say is, is this is the Skin. I cannot really -- and I think I mentioned I don't have the data to qualify what the Skin exactly means.

Q. You stated in your deposition, did you not, that your analysis showed that after May 8th the Skin was constant and rather small?

A. Yes.

MR. BOLES: Your Honor, I would just object. I think if she's going to be asking him questions about what he said in his deposition, it would be fair to put it up on the screen.

MS. HIMMELHOCH: Let's go ahead and call up his deposition at page 220, beginning at line 7 and ending at line 21.

BY MS. HIMMELHOCH:

Q. I began by asking you the question, "You did not in your work take into account any changes in the wellbore between April 20th and the shut-in of the well?"

There is an objection.

You say, "What do you mean by wellbore work?"

I say, "Any erosion in the wellbore."

There is another objection.

You say, "No, but the analysis shows that after May 8th, the Skin is constant and rather small."

Did I ask you that question, and did you give that answer?

A. Yes, and that's what I just said as well.

Q. Okay. Then I asked you, "Which implies that there is not a significant change in the wellbore over time, correct?" And you said, "Correct."

Were you asked that question, and did you give that answer?

A. Yes.

Q. Thank you. Let's move on.

Now, you state --

A. But, you know, I think we should also take into account what I said during his direct, which is this Skin here is a result of the match between the data and the model.

I mentioned in my deposition, by the way, that I had

no information to able to state what was going on in the wellbore.
Q. But your analysis certainly implies that there were no significant changes after May 8th?
A. No. The analysis imply that the Skin is rather constant.
Q. Let's move on then to a question about your assumed flow rates.
In your testimony, you referenced the fact that you had evidence that there was -- the flow at the end of the period was roughly 48,000 barrels per day, correct?
A. I gave a range, I believe.
Q. That range you took from an expert that BP selected not to testify today, correct?
A. That's correct.
Q. Let's call up D-24222.
On this graph that you were shown by opposing counsel, you showed a flow rate at the end of 42,400, and you referenced that as the Dykhuizen flow rate, correct?
A. Well, yeah. I showed that point.
Q. Now, it's fair to say, is it not, that before you -- before you issued your report, you had never read the report of Dr. Dykhuizen, correct?
A. I don't recall if I did or not.
Q. In your deposition, you were asked whether you had read his report --

A. Yes. But then I did read it, yeah.
Q. At your deposition, you still hadn't read the report of Dr. Dykhuizen; isn't that correct?
A. Since. Since my deposition.
Q. At your deposition, you had not yet read his report, correct?
A. Correct.
Q. So Dr. Dykhuizen's flow rate cannot be the basis for your putting this flow rate number at 42,400 on the last day; isn't that correct?
A. Well, he was down here for illustration.
Q. But you did not pull that number from Dr. Dykhuizen's report, did you?
A. No, I did not.
Q. In fact, Dr. Dykhuizen's best estimate of the flow rate on that last day is 53,000 stock-tank barrels per day; isn't that correct?
A. I think his number is corrected for the difference in the formation volume factor.
Q. You're aware, are you not, that Dr. Dykhuizen testified that he used a single-stage flash?
A. Okay.
Q. So Dr. Dykhuizen used a single-stage flash, just like you did, correct?
A. Yes.

Q. Dr. Dykhuizen stated that his best estimate was 53,000 stock-tank barrels per day, correct?
A. Okay, if you say so right now.
Q. Therefore, your flow curves do not match the value that's the measured value at the end of the flow period; isn't that correct, even with your higher permeability value?
A. Well, it does match the value that were given which, you know, started my process, which was given by the BP expert which is no longer -- which has not been in deposition -- I mean, has not testified.
Q. And whose report is not in evidence, whose estimate is not in evidence, correct?
A. Yeah. But the fact is, you know, when I did the work, he was a BP expert.
Q. But it is true that if you accept Dr. Dykhuizen's estimate and use 53,000 stock-tank barrels per day, neither your lower nor higher estimate would hit the measured value on the final flow day; isn't that correct?
A. Yes. Then I would not accept, you know, his number, you know, because these are my numbers and --
Q. Are you aware of any BP expert who has provided an estimate, other than the one that BP chose not to call and not to put into evidence, are you aware of any BP expert who offers an opinion regarding the value of the flow rate on the final day?

A. I don't recall.
Q. There is no BP expert testifying as to what the value is on the last day, correct?
A. Okay, if you say so.
Q. Therefore, the only testimony that this Court has heard regarding the flow rate on that last day is Dr. Dykhuizen, whose best estimate is 53,000; isn't that correct?
A. Yes.
Q. Okay. Let's move on to --
A. But, you know -- I think that's fine, but that's not too relevant for -- my results are what I've shown here.
Q. Yes, and they do not match that measured flow rate on the final day?
A. Yes.
Q. Okay. Let's move on to another topic, and that is just to confirm my understanding of how you obtained your bottomhole pressures.
As we discussed, Dr. Johnson converted your wellhead pressures to bottomhole pressures using your assumed flow rate, correct?
A. Correct.
Q. You did not review Dr. Johnson's calculations for accuracy, did you?
A. No. Because, you know, the way I work and, I suppose, other people work is you work with experts. The idea of using

experts is that you don't need to second guess them. So, you know, he has the expertise, I don't have it. So that's logical that, you know, I use his result and trust him.
Q. In other words, you don't independently have a basis for agreeing or disagreeing with his conversion to bottomhole pressures, correct?
A. I have no reason to disagree or not disagree with him.
Q. Because these bottomhole rates are what you treated as your ground truth, once they were converted, if there is an error in Dr. Johnson's calculation of those bottomhole pressures, that error would affect the accuracy of your estimate of the cumulative volume of oil released, would it not?
A. True, but I assume there is no error.
Q. You assume, but you have not investigated?
A. No. But being an expert, you know, in the same way as, you know, I would say -- you know, my clients trust my expertise and don't question my results, you know, I trust Dr. Johnson's expertise and didn't question his results.
Q. Now, you talked a bit about -- or quite a bit about deconvolution in both your cumulative volume estimate and your permeability estimate. Right now, I'm going to focus on your use of deconvolution in your cumulative volume estimate, not in the permeability estimate. Okay?
A. Okay.

Q. Isn't it true that as you used deconvolution in your cumulative volume of oil estimate, deconvolution was a means of determining your reservoir characteristics or interpretation model?
A. I'm not sure I understand the question.
Q. Isn't it true that the method -- that the reason you used deconvolution was so that you could define your interpretation model?
A. It does both. My primary objective here was not to obtain a model from the reservoir, but to, you know, find the flow rates. Deconvolution does both.
So, you know, all through my -- you know, as I say. I've used deconvolution in different ways.
Q. It's true, is it not, that one of the ways that you used deconvolution was to arrive at your interpretation model or your description of the reservoir?
A. That was, you know, one of the output, in addition to finding the rates.
Q. Isn't it true that if your interpretation model -- isn't it true that your interpretation model is an off-centered well in a long, narrow reservoir with sealed boundaries?
A. Yes.
Q. Isn't it also true that Dr. Pooladi-Darvish's interpretation model is an off-centered well in a long, narrow reservoir with sealed boundaries?

A. Well, I don't think there has been any dispute among all of the experts about the shape of the reservoir. There might have been a dispute about the size, definitely about the permeability, but not the shape.
Q. So you agree with Dr. Pooladi-Darvish's interpretation model as an off-centered well in a long, narrow reservoir with sealed boundaries?
A. Yeah. Not only with Dr. Pooladi-Darvish. I guess, you know, all the -- all the experts came to that conclusion.
Q. In developing your opinions in the case, you reviewed the deposition of Mike Levitan; isn't that correct?
A. Yes.
Q. And Dr. Levitan was a BP employee during the response, wasn't he?
A. Yes.
Q. Not only was he a BP employee during the response, he's also someone who was the author of several of the articles relating to deconvolution that you cited in Appendix D of your report; isn't that correct?
A. That's correct.
Q. In his deposition, Dr. Levitan testified that he was performing some estimates of flow rates using build-up pressures from the shut-in; isn't that correct?
A. Yes.
Q. Dr. Levitan testified that because he did not have flow

rate information, deconvolution did not reveal any more information for him in his analysis; isn't that correct?
A. That's what he said.
Q. Let's move on now to --
A. I must also add that, you know, obviously, we must disagree somewhere, because, you know, I find it possible from, you know, deconvolution to calculate the rate.
So, you know, I cannot speculate on the reason why Dr. Levitan didn't -- you know, decided not to calculate the rate because I could.
Q. But you'll agree that Dr. Levitan found that deconvolution did not add any information?
A. That's what he said during his deposition.
Q. Let's move on to focus a little bit on how your cumulative estimate of oil released compares to the other estimates that BP has offered.
Now your highest -- I apologize, I'm talking too fast. I will slow down.
Let's talk a little bit about how your cumulative volume of oil release compares to other estimates.
First, I just want to make sure that we're all clear. Your highest estimate of cumulative volume of oil released is below that of what Dr. Blunt has offered; isn't that correct?
A. If I recall, we overlap. I think his numbers are from 2.9 to 3.7. I don't remember exactly. My number is from

2.4 to 3, so obviously we overlap.
Q. You understand that he has offered as his best estimate 3.26; isn't that correct?
A. Yes, that's a best estimate.
Q. Your highest value is below that best estimate; isn't that correct?
A. Yes, but you cannot compare a fixed value with a range. You know, I provided a range. Dr. Blunt -- we are talking about Dr. Blunt, right?
Q. Yes, sir.
A. -- he is providing a range, but he's, you know, also decide to use my P10 value for permeability. So he has been on the, you know, P10 side of my estimates.
Q. Well, we'll get into your permeability estimate in a bit.
Let's call up TREX-130529.0 -- sorry, 130529.
Dr. Gringarten, this is the Annual Report of BP from 2011, correct?
A. Well, that's the first time I see it, so --
Q. But it says --
A. -- but that's what it says on --
Q. Let's go to TREX-130529.236.1.US. Maybe if you could make that blowup a little bit bigger.
MR. BOLES: Your Honor, I'm going to object to this line of questioning. Clearly, Dr. Gringarten doesn't have a foundation for interpreting statements from BP's Annual Report.

05:06:05 MS. HIMMELHOCH: This Annual Report sets forth an estimate of oil based on the work of experts, and I'm entitled to inquire into Dr. Gringarten --

05:06:13 THE COURT: All right. I'll let you go. Let's see where it goes.

05:06:17 MS. HIMMELHOCH: Thank you, Your Honor.

05:06:17 BY MS. HIMMELHOCH:

05:06:19 Q. Dr. Gringarten, you're aware, now that you're reading this, that in its report to its shareholders BP reported that they were using an estimate of total flow from the well of approximately four million barrels; that's what they said in their Annual Report, correct? The lower highlighting.

05:06:36 A. Yes.

05:06:37 Q. Did you have any input into that estimate of approximately four million barrels?

05:06:42 A. No.

05:06:42 Q. In fact, your estimate of the flow rate is a million barrels below the estimate that BP stated to its shareholders; isn't that correct?

05:06:51 A. Yes.

05:06:51 Q. Let's go on to another document.

05:06:53 THE COURT: That document was from what, an Annual Report, you said?

05:06:57 MS. HIMMELHOCH: It's their Annual Report. It's the company's Annual Report from 2011, sir.

THE COURT: Is that in evidence?

MS. HIMMELHOCH: We will be moving it into evidence, sir.

THE COURT: Okay.

BY MS. HIMMELHOCH:

Q. Dr. Gringarten, I'm going to now call up TREX-144820.

This is a staff working paper prepared by the National Commission on the BP Deepwater Horizon Oil Spill.

If we can go to TREX-114820.2.1.US. I'm sorry, I got the wrong number. I'm looking -- it's TREX number -- the page that's stamped TREX-144820.0019. Yes, that's the call-out I'm looking for.

The National Commission staff concluded that, "The emerging consensus among government and independent scientists is that roughly five million barrels of oil were released by the Macondo Well."

Assuming for a moment that that emerging consensus is correct, your estimate is two million barrels of oil below what the staff of the National Commission concluded was the emerging consensus; isn't that correct?

MR. BOLES: Your Honor, again, I would object. The witness -- there is no foundation established that this witness knows what this document is. There is no context provided here.

THE COURT: Well, I mean, really, the answer to that question is self-evident. Somebody else said five, and he said three.

MR. BOLES: Exactly.

THE COURT: Obviously, it's different.

MR. BOLES: If she wants to inquire into his numbers and whether they are higher or lower, that's one thing, in his analysis, but to compare them to snippets of documents where, for example, on the last one we don't -- the last document, we don't know where that --

THE COURT: We've had a lot of snippets in this trial so far.

MS. HIMMELHOCH: Your Honor, I simply would ask him to make an objection.

THE COURT: I'll overrule the objection, but I don't think you ought to go too far down this road.

MS. HIMMELHOCH: I am done with this document, Your Honor.

THE COURT: Okay, good.

BY MS. HIMMELHOCH:

Q. Now, Dr. Gringarten, your entire report is going into evidence here, so I want to inquire about a couple of things that you didn't talk about directly on your direct.

The first is, you were asked whether compressibility was an input into your analysis. You said no, correct?

A. Well, I mean, I'm not -- it is an input into my analysis.

Q. That was what I was trying to clear up. It is an input into your permeability analysis?
A. Yeah, but I thought the question was what's the inference of it. I must have missed the question.
Q. Before we go further on compressibility, if Dr. Blunt uses your P50 permeability as opposed to your P90 permeability -- or, sorry, P10 permeability, his cumulative discharge is still outside your range, is it not?
A. Well, he's used the -- my P10 permeability, but then he has used his own analysis for the size of the reservoir in some spots. So his final results, you know, depend not entirely on his choice of my P10 permeability.

In fact, he used my P10 permeability, if I understand, to evaluate the conductivity of the reservoir, among other things. So there is no clear relationship between his choice of my P10 and the fact that he gets something which is different from what I get.
Q. When Dr. Blunt was testifying, he acknowledged that if he used your P50 permeability value, his reservoir thickness had to be over 100 feet. You do not agree with a reservoir height of greater than one hundred feet, do you?
A. No, and I don't recall that in his deposition. Could I see?
Q. It was during the trial here, sir.
A. Yes. But I don't -- I recall some discussion about

changing some numbers in his spreadsheet, which he said was totally appropriate.

Q. Well, let me ask you: Did you agree with him that that was inappropriate?

A. Yes. I mean, I -- well, that's what he said. I don't know his spreadsheet, so I don't know what he had in his spreadsheet, but it's certain that spreadsheet is set up in a certain way, and you cannot, you know, at random put numbers in it.

What he said, if I recall, is that if you want to change the -- then you have to change the thickness, which means you have to go within the spreadsheet and do some adjustment.

Q. You've reviewed the work of Dr. Pooladi-Darvish, correct?

A. Yes.

Q. Dr. Pooladi-Darvish performed a reservoir simulation; isn't that correct?

A. Yes.

Q. Wouldn't the same principle hold true that you can't simply pluck one value out of his analysis and come to a conclusion about its effect on his analysis? You would have to go back and look at the entire reservoir simulation; isn't that true?

A. I just look at the results. You know, I didn't have -- you know, we're talking about something totally different here.

From what I understand from reading the testimony, that the government, you know, wanted to modify a number in his spreadsheet, and that's, you know, totally different than just looking at, you know, the results displayed by Dr. Pooladi-Darvish. We're talking about something totally different here.

Q. You agree, do you not, that when you perform a reservoir simulation, simply pulling out one number and plugging in another one would not honor the way in which reservoir simulations are performed?

A. Well, with respect to what? I'm not sure I understand what we are --

Q. You criticized --

A. -- trying to do here.

Q. I'm sorry, I did not mean to talk over you.

You criticized the United States because you said it was inappropriate to pull a single value out of Dr. Blunt's analysis without considering the effect of that single value on his other inputs?

A. But, again, I think we are talking about --

Q. Sir, I haven't asked you a question yet. I apologize, but let me finish my question.

So you made that criticism of the United States' counsel, and I'm asking you, wouldn't it be fair to make the same criticism if BP's counsel attempted to take a single value out of a reservoir simulation and, without considering the effect of that on other parameters, assumed what the result of that change would be?

A. I'm, you know, a little lost here.

If, you know, for instance we had access to Dr. Pooladi-Darvish's simulator, and then I plug a number, and then I say, how are we this much, then that would be the equivalent, the equivalent to defining Dr. Blunt's exam sheet, but we are talking about something totally different here.

Q. Well, we'll move on then.

Let's talk for a moment about your compressibility calculation. You did calculate a total permeability for this reservoir of approximately 18 to 19 microsips, correct?

A. Sorry, could you repeat the question? Sorry.

Q. I must have said the wrong thing. You calculated a total compressibility for this reservoir of approximately 18 to 19 microsips, correct?

A. Yeah. Possibly, I did, but okay.

Q. Do you want to see the page in your report?

A. Well, I trust you. There is no argument.

Q. Why don't we just make sure.

Let's call up TREX-11696R.0073. If we could call out the lower table there.

This is a presentation of your Monte-Carlo analysis of your compressibility numbers for the M56D and E, correct?

A. Okay.
Q. And your P50 values range from 17.84 to 18.62?
A. Yes.
Q. So I was mistaken. I'm glad you made us check.
Your permeability ranges, if you average those two numbers, somewhere around 18 microsips; is that correct?
A. That's correct.
Q. In order to calculate that total compressibility you needed an input for rock compressibility, correct?
A. That's correct.
Q. You took that input directly from Dr. Zimmerman, correct?
A. That's correct.
Q. You did not do any analysis to satisfy yourself that that was the appropriate number for the rock compressibility; isn't that correct?
A. Again -- that's correct. Again, you know, Professor Zimmerman is the expert, and therefore, you know, I have no reason to second check it.
Besides, as I mentioned before, the compressibility has no bearing from my analysis. You know, compressibility will change the size of the reservoir, but not the permeability.
So my focus on the analysis was the permeability. So, you know, that number is really incidental to my analysis.
Q. You do present, however, an estimate of the connected

volume in the reservoir, correct?
A. Yes.
Q. Does compressibility play into that estimate?
A. Yes, but it doesn't play in my calculation of the total discharge.
Q. Okay. Well, we'll come to your calculation of original oil in place in a moment.
With respect to the fluid analysis, and particularly the Appendix A of your report, that's a fluids analysis that was drawn entirely from the work of Dr. Whitson, correct?
A. Yes.
Q. Again, you did not do any independent verification of that?
A. Yeah, for the same reasons.
Q. You testified on direct that you used a single stage formation volume factor for your conversion to stock-tank barrels, correct?
A. Yes.
Q. Again, you did that in relying entirely on Dr. Whitson for the propriety of using a single-stage flash, correct?
A. Correct.
Q. Let's move on to the question of reservoir height.
I just want to confirm, Dr. Gringarten, that you used a reservoir thickness of 93 feet?
A. Correct.

Q. Dr. Blunt says the reservoir is thinner than 93 feet away from the well. Do you agree with that contention?
A. Well, I agree that that may be the case. In my case, there is -- no, if I'm doing well test analysis, okay. In well test analysis, as I've explained before, which was the schematic we showed, you know, we rely on the pressure signal, and especially the derivative, as information on, you know, the size and the characteristics and the concave -- of the reservoir.

If there was -- so for my well test analysis of the build-up after July 15th, there is no evidence of a change in thickness. Okay. So within the distance reached, you know, during -- you know, the pressure -- by the pressure signal during the -- you know, subsequent to build-up, I don't see any change in thickness.

If there were a change which is significant, I would, you know, see it because what well test analysis sees is change in mobility, which are permeability, thickness divided by viscosity, or a change in store activity, which is compressibility times porosity and thickness. If I don't see any change, then, you know, I have no reason to -- that's it.
Q. So, in your opinion, the reservoir has a thickness of 93 feet?
A. That's what I see from my well test analysis.
Q. Let's go ahead and call up D-21161.

Dr. Gringarten, isn't it correct that four of BP's experts in this case come from the same Imperial College in London?

A. Yes.

Q. Isn't it true that Imperial College conducts research for BP in the area of reservoir characterization?

A. I suppose so. I'm not aware of the details exactly.

Q. You were aware, at least since your deposition, that Imperial College of London is one of the recipients of a hundred million dollar Grant that BP gave to colleges to conduct research into reservoir characterization; isn't that correct?

A. I don't think you mentioned it in my deposition, but I heard it from the testimony of Dr. Blunt. That's the first time I heard about it. But, yes, I suppose so.

Q. You have no reason to deny that fact?

A. No.

Q. Let's go ahead and call up D-21781.

Dr. Gringarten, you explicitly rely on your colleagues from the Imperial College in your work. You use Dr. Blunt's conversion of capping stack pressures in your analysis, you used Dr. Zimmerman's number for rock compressibility, and you used Dr. Trusler's correction of the PT-B pressures; isn't that correct?

A. That's correct.

Q. If we can go ahead and call up D-21783.

In addition, you relied directly on Dr. Whitson and Dr. Johnson for additional information in your analysis, correct?

A. That's correct.

Q. If any of these individuals have made an error in his analysis, that error would carry through into your analysis; isn't that correct?

A. To, you know, different degrees.

Q. Let's now turn to what we were talking about earlier, which is your original oil in place estimate.

Your original oil in place estimate is based upon your pressure transient analysis or your well test analysis, correct?

A. That's correct.

Q. Your original oil in place, therefore, represents an estimate of the connected volume of the reservoir, correct?

A. That's correct.

Q. When you derive an estimate of connected volume from a pressure transient analysis or well test analysis, your estimate of connected volume will be directly related to your estimate of permeability; isn't that correct?

A. Yes. Yes.

Q. Therefore, if your permeability estimate were in error, that would change your estimate of connected volume as well,

wouldn't it?
A. Yes.
Q. Now, Dr. Blunt also calculated his connected area using a pressure transient analysis, did he not?
A. Yes.
Q. Therefore, his connected area is dependent on permeability, correct?
A. Yeah. He's using permeability for the connectivity.
Q. Your well test analysis honors the principle of the material balance, does it not?
A. Yes.
Q. Dr. Blunt used material balance in his analysis, didn't he?
A. Yes.
Q. Yet Dr. Blunt's connected volume does not vary proportionally with his permeability; isn't that correct?
A. I don't know. I haven't made the calculation.
Q. You've reviewed his report?
A. Yes, but I don't recall -- he provides a relationship between permeability and his volume.
Q. But you don't know?
A. Well --
Q. Let's move on now --
A. But, you know, the relationship -- and I think we covered -- we discussed that in my deposition, the distance is

proportionate to the square root of the permeability and inversely proportional to the total compressibility. So there is a relationship. It's not a linear relationship, but it is a relationship.

Q. It is true, is it not, that permeability is -- the square root of permeability is directly proportional to the distance -- or the width of the reservoir, correct?

A. You mean horizontally?

Q. Horizontally, yes.

A. Yes.

Q. The square root of permeability is also directly proportional to the length of the reservoir, correct?

A. Yes.

Q. Area is calculated by multiplying length times width, correct?

A. Yes.

Q. Therefore, isn't corrected area directly proportional to permeability?

A. Yeah, I would say.

Q. Now, let's go on to your calculation of permeability.

You indicated in your direct testimony that the pumping goes on for three to four hours in the MDT test, correct?

A. That's correct.

Q. But it's not continuous pumping, is it?

A. No. As I indicated, from time to time the tool is shut-in, and therefore there are some build-ups in between.
Q. When the well is shut-in just before the final pretest, which is what you analyzed, it has essentially returned to initial reservoir pressure, has it not?
A. I don't recall. Yeah, I don't recall. I'm not sure.
Q. You don't have any reason to dispute that right now, do you?
A. Well, normally, when you shut it, it takes quite a while before you go back to the initial pressure. So yes, I would not agree with that.
Q. How much fluid is withdrawn in a pretest?
A. A pretest, 20 cc's, but that's not what we're talking about here. Here we are talking about, you know, four hours of pumping.
Q. Four hours of pumping followed by a shut-in?
A. Yes.
Q. Followed by a pretest that withdraws 20 cc's or 1 1/3 tablespoons?
A. That's right. That's what is important, and that's where the conversion comes in, is that what has been produced is 4 hours of fluid.
Q. Four hours of fluid interrupted by a shut-in?
A. Yes. But that doesn't matter.
Q. Let's talk about -- just to confirm, I think this is clear

to the judge now, but I just want to make sure it's absolutely clear. Your estimate of cumulative volume of oil released is directly related to your permeability?
A. Yes.
Q. And so if your permeability is doubled, then your volume of oil would be doubled, correct?
A. Yeah, about.
Q. Now, you agree, do you not, that Dr. Blunt has stated in his report that permeability is typically the most uncertain parameter in reservoir engineering analysis, are you not?
A. Well, yes, he said that's uncertain, but he also said that, you know, the best way to get permeability is from a test.
Q. Right. But he -- even with that, he states that permeability is typically the most uncertain parameter?
A. In general, I would dispute that. Because that's -- you know, that's my business. I mean, I'm an expert in well test analysis. And my expertise leads me to have quite confidence on the permeability I get from well test analysis.
Q. The resolution of the pressure gauge in the MDT tool -- I apologize.
The resolution of the pressure gauge in the MDT tool that was used at the Macondo before the explosion was .02 psi; isn't that correct?
A. Correct.

Q. Let's call up TREX-011696R.N.28.1.US.

Dr. Gringarten, this is a figure from your report showing the MDT pressure measurement for the M56D layer; isn't that correct?

A. That's correct.

Q. And the yellow highlighting represents a range of .02 psi pressure measurements; isn't that correct?

A. Yes.

Q. And isn't it true that for this layer, at least, virtually all of the pressure changes that you analyzed fell within the resolution of the gauge?

A. No. Because what you didn't show is the -- you know, the pressure at the beginning of the buildup. What is important is the ratio between the -- this is not a signal. That's a resolution of the signal. And what you are showing -- what is important is the ratio of the signal to the noise, which is the resolution. And, you know, we are measuring the Delta P. The Delta P is not shown here.

Q. You are determining a trend of data, the trend of this data, correct, that's what the green line and the red line represent?

A. That's right. That's to see what would be the range of possibilities. I have analyzed the actual data and I have produced the Delta P, which we don't see here.

Q. But it is true that you are trying to determine whether

these measurements have a trend in them, correct?
A. That's correct. And the trend is being used for obtaining a range of possibility, you know, because we have uncertainty due to the resolution of the gauge. But what we are analyzing is not -- you know, that yellow part, it's the, you know, Delta P from the moment of the shut-in to the resolution, so that's the signal.
Q. And you are trying to determine whether these points make a line that goes up or a line that goes down. So you're trying to determine what trends you can get from these different points?
A. That's correct.
Q. And the measurement of these different points all fall within the resolution of the gauge?
A. But that's not the signal. The signal is a Delta P, and so it's a difference between the pressure at the time you do the shut-in and the pressure of during the shut-in, so this is really not representing what we are analyzing.
Q. For the permeability, do you not get your estimate from this time period?
A. No.
Q. You do not use these -- mean trend and average trend to obtain your estimate of permeability?
A. No. I use the Delta P. As I said, I use the difference between the pressure at the time of shut-in and the pressure

during the shut-in and that's what everybody does.

And this, what you're showing me here, is -- would be, in fact, the analysis where we only rely on, let's say, the Horner plot, as we said before, which is highly imprecise.

Q. You agree that the data -- the resolution of this gauge introduces at least some uncertainty into your analysis?

A. Yes.

Q. And you would agree that the pressure changes during the time period shown on this graph all fall within the resolution of the gauge?

A. No.

Q. During the time period that's shown on this graph?

A. No. That's not the change in pressure. The change in the pressure is the difference from the pressure at the time of shut-in.

Q. Sir, each of these points that is connected by the black line is a pressure measurement, correct?

A. Yes.

Q. And these are pressure measurements plotted against time; isn't that correct?

A. Yes. But that's not the signal. The signal is the difference in pressure between the pressure during the shut-in and the pressure at the beginning of the shut-in.

Q. I'm asking you a different question than you're answering, so let me try and make it clear again.

05:31:23 You attest in your red line and your green line to determine a trend in this data, correct?

05:31:30 A. Correct.

05:31:30 Q. And this data that you are trying to find a trend in, all of the changes in the data during this time period occur within the resolution of the gauge?

05:31:42 A. That's the reason why, you know, I tried to determine what would be the possible trend -- trends given the uncertainty of the data. But as I repeat, that's not the signal I'm analyzing.

05:31:54 Q. Now, you did an analysis of this data to come up with two estimates of permeability for the M56D layer, correct?

05:32:05 A. Correct.

05:32:05 Q. And those two analyses you called your main trend and your average trend, correct?

05:32:11 A. Yes.

05:32:11 Q. And the value that you got for your average trend when you did a detailed analysis of the permeability was 292 millidarcies; isn't that correct?

05:32:24 A. Correct.

05:32:24 Q. Then after you had also done your main trend analysis and come up with a value of 110 millidarcies, you ran a Monte Carlo analysis, correct?

05:32:33 A. Right.

05:32:34 Q. Let's call up TREX-011696-R.113.1.US. This is Table 10.

Do you need me to say that again? I do need to say it again.

Well, before we get there, you stated in your report that you considered your result from the average trend to be a reasonable upper bound for your permeability, didn't you?

A. I'm sorry. Could you repeat that.

Q. You stated in your report that the 292 millidarcy estimate that you obtained for the average trend was a reasonable upper bound for your permeability estimate, did you not?

A. Yes.

Q. Now let's go to TREX-011696-R.0113.1.US.

And this is Table 10 from your attempt at analyzing the MDT data, correct?

A. Yes.

Q. We see here on the column labeled M56D, parentheses, 144, we see that your P0 value is 281.9, correct?

A. Yes.

Q. And the P0 value represents a conclusion that there is a 0 percent probability that your permeability value will be greater than 281.9; isn't that correct?

A. Yes.

Q. And yet you had already identified a reasonable upper bound at 292, correct?

A. Well, this was an upper bound. That's not how the uncertainty is calculated. What you calculate -- as I said in my report, you calculate -- what you obtain from the analysis are, you know, dimensions, numbers. And in this particular case, you get a range of dimensions and parameters or -- dimensions and parameters, which are -- for instance, here is a pressure match.

And so we do -- you know, we get a different pressure match for -- you know, for the two bands to, you know, cover the range of points. And you go from the Monte Carlo analysis on this numbers, thinking there are other numbers, and what you end up with is the distribution I've expressed here.

Q. And, sir, again, my question, I think, was a simple one. Your Monte Carlo analysis assigns a P0 value to 281.9 millidarcies, correct?

A. Yes.

Q. And you had already calculated an average trend permeability as a reasonable upper bound of 292 millidarcies; isn't that correct?

A. Yes. And --

Q. That was all I was asking, sir.

Let's go on to another question I have about your permeability analysis.

You agree that the Macondo reservoir is a high mobility reservoir, don't you?

A. What do you call a *high mobility*?

Q. Well, let me define for the judge in case he hasn't heard this term yet. I don't believe he has.

Mobility is a measure of the permeability over the viscosity of the reservoir fluid; isn't that correct?

A. Yes.

Q. And permeability is measured in millidarcy, correct?

A. Permeability is measured in millidarcy, yes.

Q. And viscosity is measured in centipoise, correct?

A. Yes.

Q. And a reservoir of several hundred to over a thousand millidarcy per centipoise would be a high mobility reservoir; would it not?

A. Yes.

Q. And it's true that if we used even your permeability value of 238, given that you used a viscosity or mu of .205 to .249 that the ratio of 238 to .249 is roughly 1,161?

A. Yes.

Q. So the Macondo reservoir is a high mobility reservoir, correct?

A. Yes.

Q. Okay. Now, the judge saw this earlier with a different TREX number, but I'm going to call it up with the US's TREX number. Let's call up TREX-011697, please.

This is the paper that you referenced earlier in your testimony with your counsel, correct?

A. Yes.

Q. And it's a discussion of wireline formation tests, including MDT tests, correct?
A. Sorry. Could you repeat that.
Q. It's a discussion of the use of MDT tests and other wireline formation tests, correct?
A. Yeah. Except the difference here is we were talking in this paper about a pretest. You know, as -- I may not have explained to you, Judge -- there are two types of use of the wireline formation tool. One is used where you lower the tool at different levels in the reservoir and then you do what we call a pretest, which you pick -- withdraw 22 cubic centimeter of fluid, and you measure the pressure. And the purpose of that is to calculate the initial pressure at that point in the reservoir. And you do several stations, and you keep repeating it.

And so that's what we were talking about in this paper. What I've used for the MDT analysis is a sample test where we do have these pretests, but we are also pumping for several hours. And so that becomes equivalent, *de facto* to a normal well test because instead of it being a radius of investigation of a few feet, we now have a radius of investigation which is a distance of where the pressure has gone of about 600 feet, which is a significant portion of the reservoir, and therefore, we get -- you know, we are in a condition of a normal test.

05:39:15 Q. Your radius of investigation, even using deconvolution, is 657 feet roughly?
05:39:22 A. Yes.
05:39:22 Q. And the reservoir is 10,000 feet long; is it not?
05:39:25 A. But it is about 1200 feet large, you know, of the distance of the well, is about. So it's 2400 feet roughly. I don't remember exactly the numbers, but -- and so this is a significant portion.
05:39:41 Q. In this article that's up on the screen, you caution that in using the pretests, the withdrawal of 20 cc's of fluid, you may have unreliable results if you are working in a high permeability reservoir; isn't that correct?
05:39:58 A. I'm not sure we mentioned that in those words.
05:40:04 Q. Well --
05:40:06 A. But what is important, as I said before, is a signal to those ratio.
05:40:10 Q. Let's go to page -- TREX-011697.0004, please, and go to the conclusion section. And -- yes.

05:40:30 In the second bullet there, it says, "In lower permeability reservoirs, mobility is less than about 100 millidarcies per centipoise. The quality of data recorded by wireline formation test tools is suitable for pressure transient interpretation.

05:40:47 "In higher permeability, the resolution of the pressure gauge limits the quality of the data often precluding transient analysis, and the FRA method then provides the best estimate of mobility."

That is what you said in your article regarding pretests; isn't that correct?

A. Yes. It says "often precluding." And again, we are talking about the pretest. We are in totally different situation here. We have sampling and so we have pumped for many hours, and so we have all the tools to do the analysis.

Q. You have had a sampling run and then the reservoir has returned to near initial conditions, and then you have a withdrawal, just like these pretests, of 20 cc's of fluid; isn't that correct?

A. Yes. But --

Q. Yes.

A. No. The buildup benefits from the production before, and so you cannot isolate and, you know, say that the pretest is equivalent to a pretest in the beginning. That is totally wrong.

Q. I did not ask you to say that. I asked you, you had several hours of sampling, then the reservoir returned to near initial conditions and then you withdrew 20 cc's of fluid in a pretest; isn't that correct?

A. I don't think the pressure went back to the initial conditions.

Q. It went back to near initial conditions; isn't that

correct?
A. Well, what do you call *near*? I don't think. Since we have to extrapolate and calculate and use a model to get to the initial pressure, and we didn't, you know, really get back to the initial pressure.
Q. So your estimate of initial pressure is a calculation based on the MDT data; is that correct?
A. Yes.
Q. Now, you only performed a detailed analysis of the flow rate pretest; isn't that correct?
A. Yes. But I used all the buildups to verify the analysis -- consistency of the analysis. And the other tests that I ranked were shorter. So I used a series of, you know, standard techniques, which is comparing all the buildups together using deconvolution, and that's how you gain confidence in the analysis.
Q. Now, you indicated that the reason that you didn't do a detailed analysis of the other buildups was because in Figure 27 and 28 of your report, you showed that the high rate buildups would give you the same permeability model; isn't that correct?
A. Yes.
Q. And a permeability model is different than a permeability value; isn't that correct?
A. Okay. I'm not sure I used the word *permeability model*.

Q. Okay. Let's go ahead and call up your deposition. Deposition at 82, line 20 to 83, line 6.

So I start at line 20 and I ask you: "Is there any other reason why you excluded the other buildups, other than the final pretests, from your calculation of permeability?"

And you ask me: "Other than what?"

And I say: "Other than the analysis that you've discussed in Figures 27 and 28."

And we continue on to the next page and after another objection, we see: "No. Figure 28 show that the same model will apply to, you know, all the buildups, and so there is no point in redoing the analysis for each individual buildup since, you know, clearly, they give the same model."

Did I ask you those questions and did you give those answers?

A. Yeah. And, you know, those answers are, you know, still valid. I don't see *permeability model* mentioned anywhere here.

Q. Well, you said *model*. They give you the same model.

A. Okay. But --

Q. And is a model the same as a value?

A. No.

Q. And I want to look at -- a little bit closer at Figures 27 and 28. Let's begin with TREX-011696-R-N.104.01.US.

And this is Figure 28 from your report; is that correct?

A. That's correct.
Q. And if you could indulge me and make that bigger, just a little bit larger. No. You were on the right one the first time. You're stealing my thunder here. You could increase the graph a little bit. Thank you.
Now, this blue box here is what you call in your report your area of radial flow uncertainty, correct?
A. Correct.
Q. And that means that this is where you -- this is the part of the buildup that you were going analyze in order to get your permeability value, correct?
A. That's correct.
Q. And you get your permeability value by taking a particular buildup. Let's pick the blue one. These data points are the buildup, are one buildup, correct?
A. Yeah. Except I certainly would not use the blue one, because as you can see, it's of limited length. It goes to .1 second, and so I would use the black one. And most likely -- that's most likely what I've used.
Q. That's the pretest, is the black?
A. No, the black is not the pretest. Okay, maybe. I don't know.
Q. And then there is another buildup that's this red one?
A. Yes.
Q. And there is another buildup that's yellow, correct?

A. And the point of this plot is that, you know, we plot Delta Q over pressure. It's a change in pressure from the beginning of the buildup divided by the rate, you know, before that buildup.

And so what that plot shows is that they all stabilize at the same level. They get essentially the same -- they correspond to essentially the same model with some variation in parameters, and the band in blue, which is a radial flow uncertainty, is what we used for the uncertainty analysis in the calculation and the evaluation of the uncertainty and the permeability.

Q. You would agree with me, would you not, that that uncertainty band is one log cycle high?

A. Yes.

Q. Okay.

A. About, yes.

Q. And you would agree with me that the way that you would find permeability from one of these buildups is by finding the appropriate trend line of the data in this blue box area?

A. It's my drawing, you know, by different means, either by hand or through nonlinear regression, there is a horizontal line through the data.

Q. And if you chose a model that was at the top of this box, and then a model that was at the bottom of this box, it would have the same shape, but the value of permeability would differ

by an order of ten; isn't that correct?
A. Not quite ten.
Q. But close to ten?
A. About two. Because clearly, there are some points that are -- you know, that are noise. And so, therefore, here I would, and I probably did, take a factor two or three.
Q. Two or three times different?
A. Yes. And that's used for the uncertainty analysis.
Q. Okay. Let's talk now about some quick facts that I want to confirm, and then I'll have one more area after that and you'll be done with me, Dr. Gringarten.
A. Thank you.
Q. I don't know if I should be insulted by that, sir.
I just want to confirm some quick facts. The thicker layers of the reservoir will have more weight in the average permeability that you calculated; isn't that correct?
A. That's correct.
Q. And the thickest zone that you analyzed with MDT data in this case was the M56E Lower Layer; isn't that true?
A. That's correct.
Q. And so, therefore, the M56E Lower Layer would have the largest influence on your average permeability; isn't that correct?
A. Yes. I think it was -- I don't remember, sorry, the numbers, 60 feet to 40 feet.

05:49:06 Q. It's on that order?
05:49:08 A. Yes.
05:49:08 Q. I'm not going to ask you for the numbers, don't worry.
05:49:10 A. And the others are, you know, about 20, so we are talking about, you know, 60 to 40. So the other two layers, the E upper and D will still have an inference, which is, you know, very close, you know, 40 to 60, the inference would be almost similar.
05:49:34 Q. But individually, the M56E layer as compared to either the M56E upper or the M56D will have a greater influence?
05:49:46 A. Yeah. But you have to look at all of that together.
05:49:49 Q. Yes. But if you have an error in your M56E Lower Layer and you have underestimated the permeability for that layer, it will have a larger impact on your average permeability than if you had an error in your M56E Upper Layer; isn't that correct?
05:50:03 A. Could you repeat. Sorry.
05:50:09 Q. Yeah. It was probably a little convoluted.
05:50:15 If you have underestimated the permeability for the M56E Lower Layer, that would have a greater impact your average permeability than if you had underestimated the value of the permeability for the M56E Upper Layer, isn't that true?
05:50:29 A. Well, you would have, you know, an inference within the ratio of 60 to 40.
05:50:36 Q. Would it be 60 to 40 comparing the M56E Lower to the M56E Upper?

A. Yeah. But you don't compare the two. You have three layers. That's what you have to take into account.
Q. You agree that the M56F layer is only 6.5 feet thick, correct?
A. That's correct.
Q. And, in your opinion, the M56F layer did not have a significant influence on your overall thickness based average; isn't that correct?
A. Yeah. It's the smallest influence of all the three layers -- the four layers.
Q. And you agree that M56E Upper Layer has the lowest permeability of the three layers that were analyzed using MDT data?
A. Start again. Sorry.
Q. Probably the court reporter is grateful for your slowing me down.
You agree, do you not, that the M56E Upper Layer has the lowest permeability of the three layers analyzed by the MDT tool?
A. Well, if I recall, the -- you know, the -- the most likely probability are, you know, 116, 117, and 280 something.
Q. And you agree that the M56E Upper Layer has the lowest of the three?
A. Well, if you say 116 is less than 117, you're right. But I would call them, you know, very similar.

Q. Let's wrap up by talking about an estimate of permeability that was performed by BP during the response.

As part of its efforts to characterize the reservoir for purposes of stopping the spill after the explosion, BP had its internal experts prepare an estimate of the permeability of the reservoir in July of 2010; did it not?

A. Yes.

Q. And let's call up TREX-003533.

And this is that analysis, correct?

A. Okay.

Q. Do you agree?

A. Yes. I have difficulty reading it.

Q. We can call that out for you.

A. Okay. Good. All right. Yes.

Q. Okay. And now let's go to page 35 of this document. And if we can call out the bullet at the top, *Mobility*. Yes, that bullet.

And at the time of the response, from this bullet, we can see that BP had available to it the MDT data, did it not?

A. Okay. Yes. And that's what we had found.

Q. And it states that mobility from the pretests confirm that the sands have high permeability in the 100 millidarcies range, correct?

MR. BOLES: Objection, Your Honor. Lack of foundation. That's important because of the lack of permeability that we've talked about with the witnesses.

MS. HIMMELHOCH: Your Honor, they questioned him on direct regarding what use other experts had made of the MDT data.

THE COURT: I overrule the objection.

EXAMINATION BY MS. HIMMELHOCH:

Q. This is what they stated with respect to the MDT data; isn't that correct?

A. Well, that's what written here, yes.

Q. And on page 13, if we go to TREX-003533, and call out the first paragraph of the summary.

"Having looked at the data, including some of the MDT data, BP concluded, using its internal experts during a response, that the range of permeability averages for this reservoir were between 250 and 500 millidarcies"; isn't that correct?

A. Where do I read?

Q. It's the second to last line.

A. Yeah, I see the last line. I'm trying to look, you know, what is before.

Q. I'm not suggesting that it was calculated from MDT data. I'm simply asking to you confirm that knowing that there was MDT data, BP chose to calculate its estimate of the permeability as 250 to 500 millidarcies during the response; isn't that correct?

A. Well, that doesn't seem -- you know, I may be missing something here, because if I read the next line, it says, "Permeability was calculated using a post permeability transformed based on sidewall core data analysis."

So I don't see any mention here of MDT.

Q. We are in the same document, do you agree, sir?

A. Yes.

Q. And the document on the prior page we were looking at, you agree, showed that they were aware of the MDT data, correct?

A. Yes.

Q. And being aware of the MDT data, the internal experts at BP chose a different method to the estimate the permeability and concluded that the permeability range was between 250 and 500 millidarcy; isn't that correct?

MR. BOLES: I object, lack of foundation for his knowledge about any other BP expert or witness these numbers refer to.

THE COURT: I overrule the objection.

BY MS. HIMMELHOCH:

Q. Do I need to repeat the question, sir?

A. Yes.

Q. Aware that the MDT data existed, BP's internal experts chose to use a different methodology to calculate permeability, and the conclusion that they drew during the response was that the permeability averages in the range of 250 to 500

millidarcy; isn't that correct?
A. Well, that's -- they say arithmetic, and that puzzles me, and log derived. So also they mentioned MDT at the beginning. They don't give anything special about MDT.
What they refer to here is log derived permeability they are using opposed to permeability transformed, so I don't see the connection between the two.
Q. Sir, you agree that at the time that they wrote this paragraph, because this paragraph is in the same document as the previous paragraph we looked at, these internal experts were aware of the MDT data, correct?
A. You know, they seemed to be aware.
Q. They chose a different method to estimate the permeability, and using that different method they concluded that the permeability averages in the range of 250 to 500 millidarcy; isn't that correct?
A. That's correct, but I have --
MS. HIMMELHOCH: Thank you. I have no further questions.
THE COURT: Redirect.
MR. BOLES: Yes, please, Your Honor.
REDIRECT EXAMINATION BY MR. BOLES:
Q. Let's start where you just left off, Dr. Gringarten, that BP technical memorandum, TREX-3533, that Counsel characterized as showing that BP's internal experts characterized the

permeability as 250 to 500 millidarcies. Do you remember that line of questions you were just asked?
A. Yes.
Q. Do you know, Dr. Gringarten, whether that number was actually used by BP modelers in that range that's reported?
A. No, I don't.
Q. Have you read the expert report of Dr. Kelkar?
A. Yes.
Q. Does Dr. Kelkar take the same permeability numbers that are reported in that memorandum and come up with a number of 300 millidarcies for his PI calculation in his expert report?
MS. HIMMELHOCH: Objection, beyond the scope of Dr. Gringarten's report.
THE COURT: Overruled.
THE WITNESS: Yes.
BY MR. BOLES:
Q. Dr. Gringarten, do you know whether BP's internal reservoir modelers took the number that was referred to that we just saw in TREX-3533, and applied a scaling factor to go from those air permeability numbers to an effective permeability to oil that they actually used in modeling to characterize a reservoir?
MS. HIMMELHOCH: Objection. Leading, lack of foundation.
MR. BOLES: The whole line of questioning is lack of

foundation, Your Honor.

THE COURT: Overruled.

THE WITNESS: If I recall, it was done by the oil saturation, which was 0.87.

BY MR. BOLES:

Q. Dr. Gringarten, do you -- you were shown a graph, Figure 27 from your report, showing the radial flow stabilization plots on page 23 of your expert report, do you remember that?

A. Yes.

Q. Is that kind of data and variability in the data something that you see on a regular basis in your well test analysis work that you -- where you interpret data to give your oil industry clients a permeability number?

A. Yes.

Q. Did you apply standard methods to deal with the noisiness in the data?

A. Yes.

Q. You were asked on cross about the P0 permeability of 281 millidarcies and an upper bound of 292 millidarcies, do you remember that?

A. Yes.

Q. I think you were about to say something else in your answer. Do you have something you want to add to that?

A. I'm not sure I recall what I wanted to say.

Q. This is when you were talking about the P0 permeability of 281 and an upper bound of 292. You had started to give an answer, and I think you might have been cut off.

A. Well, what I was explaining is how the uncertainty is calculated. What we get from the match is not the permeability directly, but a number which has permeability in it.

What we input into the -- calculation is the upper limit of that number, which includes permeability, viscosity, rate and so forth. Then we do a Monte-Carlo on the error uncertainty on every member of the number, and including the quality of the match.

That is what is giving the probability distribution on every parameter, including the permeability.

Q. Dr. Gringarten, you were also shown your article about the use of wireline tools for well test analysis, do you recall that?

A. That's correct.

Q. That article discussing some potential limitations or precautions that need to be used in using those kind of tools for well test analysis?

A. Yes.

Q. Do those limitations apply or limit the reliability of the analysis you've done in this case?

A. No.

Q. Why not?

A. Because, as I explained, we are analyzing sampling tests, and so -- which has four hours, three to four hours of sampling before.

So the final build-up or the build-ups that I have analyzed benefit from that extended production time, sampling time, which, you know, extend the radius of investigation.

So we are in, as I say, the condition of the normal test. If we had run a DST, which is, you know, the test that you -- between packers that are attached to the drilling pipes, which is a typical test we do once a well has been completed, then we would reach about the same radius of investigation.

So with the sampling test -- with the -- yeah, sampling test, we are essentially in the condition of a real test.

Q. Now, those pumping tests that you're referring to now, is that what you --

A. Sampling tests.

Q. -- sampling tests, is that what you looked at in your analysis from the MDT tool to calculate permeability at Macondo?

A. That's correct.

Q. How long is -- what's the comparison of the pumping duration and the resulting radius of investigation of those sampling tests as opposed to these pretests being described in your article?

A. If you don't use deconvolution, the radius of investigation, which is the distance which on the pressure signal in the pretest, including the last one, would be 60 feet, so we have reached ten times the distance that we would have reached by analyzing -- you know, not taking -- you know, analyzing just the pretest.

Q. On direct, Dr. Gringarten, you were asked whether PT-B pressures can be used reliably in calculating cumulative flow. Do you remember that?

A. Yes.

Q. And do you think that any of the other experts in this case who have used PT-B pressures have used that data reliably in calculating cumulative flow?

MS. HIMMELHOCH: Objection, goes beyond the four corners to the extent that they are inquiring about anybody other than Dr. Kelkar and Dr. Pooladi-Darvish.

MR. BOLES: Well, presumably counsel's question is going beyond just Dr. Gringarten's analysis, so she's opened the door to this line of inquiry.

MS. HIMMELHOCH: I did not ask him to opine on the propriety of Dr. Griffiths' use of the data. He testified in his deposition that he had not read the report of Dr. Griffiths. I think it's inappropriate and beyond the four corners of his report to ask him to opine now as to Dr. Griffiths' use of MDT.

MR. BOLES: I'll withdraw the question if we'll agree on stipulating that Dr. Gringarten's answer on PT-B pressures being used reliably was only referring to his work.

MS. HIMMELHOCH: I am not so stipulating, but I did not ask him to opine on the proprietor of its use in a particular methodology.

THE COURT: Okay, you've won, Ms. Himmelhoch. Don't keep going, I may change my mind.

MS. HIMMELHOCH: I've learned my lesson, sir.

BY MR. BOLES:

Q. Maybe I could ask this, Dr. Gringarten. Why is it that you think the work you have done using PT-B pressures is a reliable way of calculating cumulative flow?

A. Well, because I use deconvolution. Again, it's reliable within the uncertainties, which I have described.

Q. When you mention deconvolution, I think that counsel asked you some questions about how you use deconvolution to convert the pressures measured at the PT gauge at the wellhead down to reservoir pressures. Do you recall that?

A. Could you ask the question again? Sorry.

Q. Sure. The discussion about your Option 1 and your Option 2 was a reference to the process you used to convert the PT-B pressures, which were measured at the wellhead, down to reservoir depth.

A. Yes.

06:06:10 Q. Why did you do that, Dr. Gringarten?
06:06:11 A. You mean why did I convert pressure from the surface to the bottom?
06:06:19 Q. Right.
06:06:19 A. Because my experience -- and we have published a paper on that -- is that the wellhead pressure does not fully represent what's going on in the reservoir, you know, because of the influence of the well --

06:06:37 In well tests, in normal well tests, the preferred method is to have measurements at the bottom as well. So what I was attempting here is to get back to the normal condition of the test by converting the wellhead pressure into bottomhole pressure.
06:07:03 Q. Now, it was mentioned in cross-examination that you did that conversion. As one step of that conversion, you had to provide estimated rates of flow to Dr. Johnson, so that he could give you an input on the effects of pressure conversion for multiphase flow and other complexities from the flow rate; is that correct?
06:07:25 A. That's correct.
06:07:25 Q. You chose two different simplified assumed flow rates as a starting point for your arriving at flow rates that you gave to Dr. Johnson?
06:07:38 A. That's correct.
06:07:39 Q. Now, did the choice of those flow rates affect the

cumulative number that you've calculated and presented to this Court?
A. Well, they do in the sense that the purpose of choosing two initial flow rates is to end up with a range of pressure at the bottom of the well. So it's a different process -- you know, a separate process. We need to convert to the bottom of the well, and for that then we need to have some assumption on the rate. That's for just the purpose of conversion.
So I use a range of rates which give me a range of pressure, you know, combined with a range of flow path. I take that as -- you know, I end up with four cases that would represent a reasonable range of expected bottomhole pressures.
Q. Let's just briefly discuss the two flow rates that you began with in that process. One was assuming a constant flow rate of 45,000 stock-tank barrels per day throughout the incident, correct?
A. Yep.
Q. One started lower, at 30,000, and then jumped up to 45,000, correct?
A. That's correct.
Q. Which one of those two, Dr. Gringarten, the lower flow rate assumption or the higher flow rate assumption, results in a higher cumulative flow in your analysis?
A. The lower assumption.
Q. Why is that?

A. Well, because the higher the flow rate you start from, you know, the higher the pressure drop because of friction. We are talking about, you know, flowing now. If you start with a higher rate, then you are going to calculate a higher pressure drop between the top and the bottom.

Therefore, since the wellhead pressure is fixed, you are going to come up with a higher bottomhole pressure. So with a higher rate assumption at the beginning, you end up with a lower pressure drop at the bottom from the initial pressure. That then would give you a lower cumulative. So the higher you start with, the lower cumulative you end up with.

Q. As a check on this process that you undertook to try to convert PT-B pressures from the wellhead level down to reservoir level, did you also check that against using the same methodologies you described in your report, and just using the raw unconverted PT-B pressure?

A. Yes. I did the same analysis on the wellhead pressure. Using the wellhead pressure, then I calibrated the, you know, rate to the most likely permeability of 238. That gave me a cumulative of 2.7 million stock-tank barrel. So that's in between the -- that's within the range I obtained by converting to downhole.

Q. You were asked on direct about that first pressure that you -- that's shown in your report, the pressure measurement from the MDT tool of the Macondo Reservoir pressure on

06:11:25 April 12th. Do you remember that?
06:11:26 A. Yes.
06:11:27 Q. You were asked whether or not that was a flowing pressure. Do you remember that?
06:11:31 A. Yes.
06:11:32 Q. Does that matter for the analysis you were doing?
06:11:34 A. No. You know, it's a static pressure.
06:11:43 Q. Is a static pressure appropriate for using in the analysis you've done in the case?
06:11:47 A. Yes.
06:11:48 Q. You were asked also about the -- what you did with respect to the gap in pressure data between that April 12th measurement and May 8th when the PT-B started measuring pressure. Do you recall that?
06:12:02 A. Yes.
06:12:03 Q. You were asked about the interpolation that you did between the April 12th measurement and the May 8th measurement. Do you recall that?
06:12:08 A. Yes.
06:12:12 Q. Now, sir, do you have an opinion as to whether -- on an alternative approach, which would have been to ignore the April 12th pressure reading and simply infer the pre-May 8th pressure by extrapolating a trend line from the post-May 8th PT-B pressure?
06:12:29 MS. HIMMELHOCH: Objection, beyond the four corners of

his report.

MR. BOLES: Well, he chose the method he did. He's been questioned about it. I think we should ask him for his opinions and reasons for doing it the way he did it.

THE COURT: I'll let him answer. Go ahead.

BY MR. BOLES:

Q. Did you understand my question?

A. Yes. So you said instead of using the initial pressure obtained from the MDT, I would have extrapolated the trend --

Q. From post-May 8th back in time.

A. From post-May 8th back to Time Zero --

Q. Yes.

A. -- at the start of the spill. Well, that would be improper.

Q. Why?

A. Because that's not the way it is.

Plus, if you do that, then you end up with a higher rate, which would necessitate the Skin which would be very negative and unphysical. So I don't think that would work.

Q. Dr. Gringarten, you were asked some questions about the final flow rates at the end of the incident as shown on a demonstrative showing some of the flow rates you've reconstructed for this case. Do you recall that?

A. Yes.

Q. Now, when you take your relative flow rates from

deconvolution and then calibrate them through well test analysis to the permeability you got from the MDT tool, does that yield an estimate of final day flow rate?
A. Yes.
Q. Were those shown on those graphs?
A. Yes, when -- you know, the end part.
Q. Now, you were asked about Dr. Dykhuizen's final day flow rate. I think counsel said it was 53,000 stock-tank barrels per day. Do you remember that?
A. Yes.
Q. If you were to subtract a 20 percent uncertainty range from 53,000 barrels per day, how would that compare to the final day flow rate that was shown in that brown on your plot that you were --
A. It would be about it.
Q. Last question for you, Dr. Gringarten, is that you were shown a table of probabilistic range of numbers for total compressibility. Do you remember that?
A. Yes.
Q. The numbers went from something like 15 to 20 microsips, as I read it?
A. Yes, something like that is correct, yes.
Q. Is that number referring to rock compressibility?
A. I think.
Q. I'll refer you now to the total compressibility numbers

that were on that table.
A. Yeah. I mean, the total compressibility is the weighted sum of the compressibility of oil and water weighted with the saturation of oil and water, plus the compressibility of the rock.
So in the uncertainty analysis, I have taken into account all of the uncertainty among the elements, and I end up with an uncertainty of the total compressibility, because the numbers you cited were, you know, for the total compressibility.
Q. That's an addition of rock compressibility plus water compressibility plus oil compressibility?
A. That's correct.
Q. Do you know what the largest contributor is to that total of what's in the range between 15 and 20 microsips on that chart?
A. Well, it's the oil permeability -- this is the compressibility, sorry.
Q. You said you got your rock compressibility number from Dr. Zimmerman, correct?
A. That's correct.
Q. That's the number you believe is the correct one to use in your analysis?
A. I have no reason to -- not to believe that.
MR. BOLES: That's all I have. Thank you.

THE COURT: You're done. Thank you, sir.
THE WITNESS: Thank you very much.
THE COURT: All right. We're going to recess until the morning. Have we lined up our witnesses for tomorrow, Mr. Brock?
MR. BROCK: Yes. Is court tomorrow 8:00 to 12:00?
THE COURT: Yes, I have to recess at 12:00. I have an en banc meeting that's going to last all afternoon.
MR. BROCK: So we should be able to do Mr. Merrill, who is a fact witness, and Dr. Zaldivar, who is an expert, tomorrow morning.
I'm very optimistic that we would be able to cover Dr. Momber, Dr. Nesic and Dr. Johnson on Thursday. I'll need to get this evening a list of the US experts and the order for Friday.
THE COURT: Mr. Merrill is testifying as a fact witness?
MR. BROCK: As a fact witness.
THE COURT: Okay. Any other matters?
MS. HIMMELHOCH: Your Honor, we'll need to discuss amongst ourselves the order of rebuttal witnesses. At this time, we do intend to call all three. We believe they can easily be completed on Friday, so we'll all be facing all three on Friday, if they conclude on Thursday.
MR. BROCK: We would like to know the order in case we

slip into Friday morning with our case.

THE COURT: Can you let them know by this evening, or tomorrow at the latest?

MS. HIMMELHOCH: Can I have until 8:00 a.m. tomorrow morning, and we'll advise the Court first thing tomorrow morning?

THE COURT: Okay.

MR. BROCK: It would be helpful for us to know that tonight. I let them know this this morning. I'd ask to know tonight. That's what we've been doing.

THE COURT: The order of the possible rebuttal?

MR. BROCK: The order of witnesses, yes.

THE COURT: Can you let them know sometime this evening?

MS. HIMMELHOCH: We'll let them know by 9:00 p.m. tonight.

THE COURT: Okay, thank you.

Anything else? All right. Everyone, have a good evening. We'll see you at 8:00 a.m.

THE DEPUTY CLERK: All rise.

(WHEREUPON, at 6:18 p.m., the Court was in recess.)

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REPORTER'S CERTIFICATE

I, Cathy Pepper, Certified Realtime Reporter, Registered Merit Reporter, Certified Court Reporter of the State of Louisiana, Official Court Reporter for the United States District Court, Eastern District of Louisiana, do hereby certify that the foregoing is a true and correct transcript to the best of my ability and understanding from the record of the proceedings in the above-entitled and numbered matter.

s/Cathy Pepper

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